TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AIR QUALITY PERMITS

PROPOSED AIR QUALITY PERMIT NUMBERS 147681, PSDTX1522, AND GHGPSDTX172

APPLICATION AND PRELIMINARY DECISION. Jupiter Brownsville, LLC, 440 Louisiana St Ste 700, Houston, TX 77002-1054, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of proposed State Air Quality Permit 147681, issuance of Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1522, and issuance of Greenhouse Gas (GHG) PSD Air Quality Permit GHGPSDTX172 for emissions of GHGs, which would authorize construction of the Centurion Brownsville located at 11700 RL Ostos Road, Brownsville, Cameron County, Texas 78521. This application was processed in an expedited manner, as allowed by the commission’s rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. The existing facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide. In addition, the facility will emit the following air contaminants: Hazardous Air Pollutants (HAPS), hydrogen sulfide and sulfuric acid mist.

The degree of PSD increment predicted to be consumed by the existing facility and other increment-consuming sources in the area is as follows:

Sulfur Dioxide

Maximum Averaging Time	Maximum Increment Consumed (μg/m^3)	Allowable Increment (μg/m^3)
3-hour	417	512
24-hour	31	91
Annual	2	20

PM_{10}

Maximum Averaging Time	Maximum Increment Consumed (μg/m^3)	Allowable Increment (μg/m^3)
24-hour	0	30
Annual	4	17

Nitrogen Dioxide

Maximum Averaging Time	Maximum Increment Consumed (μg/m^3)	Allowable Increment (μg/m^3)
Annual	3	25

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (μg/m^3)	Allowable Increment (μg/m^3)
24-hour	7	9
Annual	1	4

This application was submitted to the TCEQ on July 14, 2017. The executive director has determined that the emissions of air contaminants from the existing facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Harlingen regional office, and at the Brownsville Public Library, 2600 Central Boulevard, Brownsville, Cameron County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Harlingen Regional Office, 1804 W Jefferson Ave, Harlingen, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above (Brownsville Public Library) provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=25.961111&lng=-97.355277&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting to the Office of the Chief Clerk at the address below. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all relevant and material or significant public comment. **The response to comments, along with the executive director's decision on the application, will be mailed to everyone who submitted public comments or is on a mailing list for this application. The mailing will also provide instructions for requesting a contested case hearing or reconsideration of the executive director's decision.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 147681 and for PSD Air Quality Permit Number PSDTX1522. There is no opportunity to request a contested case hearing regarding the portion of the application for GHG PSD Air Quality Permit Number GHGPSDTX172. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. A person who may be affected by emissions of air contaminants, other than GHGs, from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a

contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application for the portion of the application for GHG PSD Air Quality Permit GHGPSDTX172. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 147681 and for PSD Air Quality Permit Number PSDTX1522, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the State Air Quality Permit Number 147681 and for PSD Air Quality Permit Number PSDTX1522 and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www14.tceq.texas.gov/epic/eComment/, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Jupiter Brownsville LLC at the address stated above or by calling Mr. Tom Ramsey, Chief Executive Officer at (713) 600-1600.

Notice Issuance Date: April 4, 2019

2100Special Conditions

Permit 147681, PSDTX1522, and GHGPSDTX172

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources – Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits and other conditions specified in that table.

   Planned startup and shutdown emissions due to the activities from facilities and emission points identified in Special Condition 59 are authorized provided the facility and emissions are compliant with the respective MAERT and Special Conditions 59-71 of this permit.

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A, General Provisions.

   B. Subpart Db, Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart Kb, Volatile Organic Liquid Storage Vessels.

   D. Subpart Ja, Petroleum Refineries.

   E. Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries.

   F. Subpart QQQ, Petroleum Refinery Wastewater Systems.

   G. Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.

4. These facilities shall comply with all applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61:

   A. Subpart A, General Provisions.

   B. Subpart FF, Benzene Waste Operations.

5. These facilities shall comply with all applicable requirements of EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

   A. Subpart A, General Provisions.

   B. Subpart Y, Marine Tank Vessel Loading Operations.

   C. Subpart CC, Petroleum Refineries.

D. Subpart UUU, Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

E. Subpart EEEE, Organic Liquids Distribution (Non-Gasoline).

F. Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines.

G. Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters.

Storage of Volatile Organic Compounds (VOC)

6. A. Storage tank service for tanks vented to atmosphere is limited as follows.

Tank FIN	EPN	Tank Type	Product(s)	Maximum Fill/withdraw rate per tank (gallons per hour)
T-100-1 through T-100-9	T-100-1 through T-100-9	IFR	Crude condensate, gasoline, reformate, diesel, gas oil,	1,260,000
T-150-1 through T-150-12	T-150-1 through T-150-12	IFR	Crude condensate, gasoline, reformate, diesel, gas oil, or MTBE	1,260,000
T-250-1 through T-250-6	T-250-1 through T-250-6	IFR	Crude condensate, gasoline, reformate	1,260,000
T-250-2, T-250-4, and T-250-6	T-250-2, T-250-4, and T-250-6	IRF	diesel, gas oil	1,260,000
TK-842	EPN PK-712	VFR	Spent Chloride Caustic	333
T-843 A/B/C	EPN PK-712	VFR	Spent Sulfide Caustic	333
T-891A/B	T-891A/B	VFR	Distillate fuel oil no. 2	875
M-823-T1	SM-823-T1	VFR	33% HCl solution	925
M-871-T06	M-871-T06	VFR	Sulfuric Acid	528

B. The Benzene content of any Gasoline stored at the site shall not exceed 3% Benzene by weight in the liquid.

C. Storage tank Facility Identification Numbers (FINS) T-250-2, T-250-4, and T-250-6 are prohibited from storing diesel, gas oil, or any other product with a vapor pressure less than or equal to 0.50 psia.

7. Storage tanks are subject to the following requirements: The control requirements specified in parts A-C of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 psia at the maximum feed temperature or 95 degrees Fahrenheit (°F), whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

   A. The tank emissions must be controlled as specified in one of the paragraphs below:

      1. An internal floating deck or "roof" shall be installed. A domed external floating roof tank is equivalent to an internal floating roof tank. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

      2. An open-top tank shall contain a floating roof (external floating roof tank) which uses double seal or secondary seal technology provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

   B. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and any seal gap measurements specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, August 11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates inspections are performed, any measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

   C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

   D. The tanks shall be designed to completely drain its entire contents to a sump in a manner that limits the volume of free-standing liquid in the tank or the sump as follows:

Nominal Piping Size of the Sump Pipe (inches)	Volume of Free-Standing Liquid in the Tank or Sump (gallons)
2	9
3	14
4	32
6	75

   E. Tanks shall be constructed or equipped with a connection to a vapor recovery system that routes vapors from the vapor space under the landed roof to a control device.

F. All emissions from Spent Chloride Caustic Tank T-842, and Spent Sulfide Caustic Tanks T-843A, T-843B, and T-843C shall be routed to the Main Flare (EPN PK-712).

G. All vents from the 33% HCL Acid Injection Tank (FIN M-823-T1) shall be routed to scrubber EPN SM-823-T1. During periods that the scrubber is out of service due to planned maintenance, no liquid shall be added to the tank.

H. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white or unpainted aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

I. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12-month period. The record shall include tank identification number, control method used, tank capacity in gallons, name of the material stored, VOC molecular weight, VOC monthly average and monthly average high temperatures in degrees Fahrenheit, VOC vapor pressures at the monthly average and monthly average high material temperatures in psia, VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures.

Emissions from tanks shall be calculated using the methods that were used to determine the MAERT limits in the permit application (PI-1 dated July 13, 2017). Sample calculations from the application shall be attached to a copy of this permit at the plant site.

J. In addition to the records specified in paragraph I of this condition, the permit holder shall maintain records of the following:

(1) The date, start time, and end time that scrubber EPN SM-823-T1 is out of service due to planned maintenance.

(2) Records of Hydrochloric Acid (HCL) concentration stored in storage tank FIN M-823-T1. Certificate from the supplier may be used to satisfy this requirement.

8. The true vapor pressure of any liquid stored at this facility in atmospheric tanks shall not exceed 11.0 psi. Storage of any product with a true vapor pressure of 11.0 psi or greater at ambient conditions in tanks vented to the atmosphere is not authorized by this permit.

9. The dissolved hydrogen sulfide (H_2S) in the crude oil or crude condensate stored in any tank shall not exceed 10 parts per million by weight (ppmw) in any sample.

A. In order to demonstrate compliance with this Special Condition, the permit holder shall determine the dissolved H_2S concentration of each crude stock to be stored in the tanks identified in Special Condition 6. The H_2S concentration may be determined using method ASTM UOP163-10 or ASTM D7621-14. Any additional method of sampling and analysis used must be approved by the Texas Commission on Environmental Quality (TCEQ). Product analysis (laboratory certificates of

analysis) from the delivering source, are acceptable in place of on-site analysis. Records of Certificates or sampling results shall be kept for a period of five years.

B. The frequency of sampling, if laboratory certificates of analysis are not used, shall be monthly.

C. Records of H_2S concentrations measured to meet the requirements of this condition shall be maintained at the plant site.

10. Pressure tanks shall be maintained such that there are no emissions to the atmosphere during normal operating conditions (including filling operations).

Sour Water

11. During periods that the Feed Preheater (EPN H-001) is out of service, emissions from the Sour Water Flash Drum (FIN D-854) and Sour Water Tank (FIN T-851) shall be vented to the Main Flare EPN (PK-712).

Process Heaters & Reboilers

12. Fuel for the heaters and boilers authorized by this permit may consist of refinery fuel gas, natural gas, or a blend of the two fuels.

13. The natural gas shall contain no more than 0.2 grains of total sulfur per 100 dry standard cubic feet (dscf). The natural gas shall be sampled every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

14. The permit holder shall not burn any fuel gas that contains H_2S in excess of 60 ppmvd determined on a 1-hour rolling average basis

15. The holder of this permit shall install a continuous H_2S monitoring system in a portion of the fuel gas system common to the fuel gas combustion devices in accordance with the fuel sulfur monitoring requirements of 40 CFR §60.107a(2).

    The fuel gas from the fuel gas mix drum shall be sampled once per week to determine HHV. Test results from the fuel supplier may be used to satisfy this requirement for purchased fuel gas supplies.

    Process fuel gases that are not routed to the fuel gas mix drum shall be monitored for H_2S content and HHV prior to being used as fuel.

    On a monthly basis, the monthly average and 12 month rolling average fuel sulfur content and HHV shall be determined and records maintained. Upon request by the Executive Director of the Texas Commission of Environmental Quality (TCEQ) or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or analysis of the fuel,or shall allow the air pollution control agency representatives to obtain a sample for analysis.

16. Opacity of emissions from boiler and heater stacks must not exceed 5 percent averaged over a six-minute period.

    Opacity shall be determined by the U.S. Environmental Protection Agency (EPA) Test Method 9 during the initial compliance testing and at least once per year thereafter. In lieu of performing a required opacity test, the permit holder may verify that there are no visible emissions as determined by EPA Test Method 22.

17. A. Each of the following units shall not exceed NOx and CO emissions from the units following units shall not exceed the specified emission limits.

EPN	FIN	Name	Limits
H-001	H-001	Feed Preheater	0.015 lb NOx/MMbtu on a 1-hour average 0.010 lb NOx/MMbtu on a rolling 12-month average 50 ppmvd CO at 3% Oxygen on a 1-hour average 10 ppmvd NH3 at 3% Oxygen on a 1-hour average
H-002	H-002	Debutanizer	
H-CCR12	H-201	CCR Preheater	
	H-202	First Interheater	
H-CCR34	H-203	Second Interheater	
	H-204	Third Interheater	
M-801	M-801	Steam Boiler	

    B. The NOx emission limitations of this condition shall be achieved by use of low NOx burners in combination with Selective Catalytic Reduction (SCR).

    C. Compliance with the NO_X and CO emission limits of paragraph A shall be demonstrated through use of CEMS.

    D. Compliance with the NH_3 emission limits of paragraph A shall be continuously demonstrated using one of the options specified in Special Condition 44.

18. Combustion units below shall not exceed the NOx and CO emissions limits specified.

EPN	FIN	Name	Limits
H-CCR5	H-205	Stabilizer Reboiler	0.035 lb NOx/MMbtu on a 1-hour average. 50 ppmvd CO at 3% Oxygen on a 1-hour average.
H-101	H-101	HDS Heater	
H-401	H-401	Reactor Heater	
H-402	H-402	Stripper Reboiler	

19. The Stabilizer Reboiler and HDS Heater (FINs H-205 and H-101) shall not exceed a maximum firing rate of 98.3 MMbtu/hr and 98.4 MMBtu/hr respectively. An increase in maximum firing rate above the limits specified in this condition must be authorized under Title 30 Texas Administrative Code § 116.116(b).

20. For heaters and boilers not equipped with a CEMS, the permit holder shall install and operate totalizing fuel flow meters to measure the fuel gas usage for each heater and reboiler and fuel usage for each shall be recorded monthly.

Each totalizing fuel flow meter shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent of the unit's maximum flow.

Quality-assured (or valid) data must be generated when the heater or reboiler is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the boiler or heater operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Loading Operations

21. All lines and connectors for all loading operations shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.

22. A. This permit authorizes loading of the following liquids having a vapor pressure less than 0.50 psia;

Diesel	Gas Oil

B. This permit authorizes loading of the following liquids having a vapor pressure greater than or equal to 0.50 psia:

Gasoline	Reformate
Propane	

C. Emissions to the atmosphere during propane loading operations are not authorized by this permit. This does not include disconnects after loading operations have been completed as authorized in EPN SG-FUG.

23. The following limits apply to loading of ocean going ships and inland barges:

A. Loading of ocean going ships is limited to a combined loading rate of 30,000 barrels per hour (bbls/hr) for each of the three loading berths. The loading of inland barges is limit to a combined limit of 10,000 bbls/hr for each of the three loading berths.

B. Each vapor combustor is limited to emissions from loading a maximum of 15,000 barrels per hour

C. Each berth is authorized to load either 1 ocean going vessel or up to two inland barges.

D. Collected vapors from loading of liquids having a vapor pressure greater than or equal to 0.50 psia to marine vessels shall be routed to one of the marine vapor combustors (EPNs VC-1, VC-2, VC-3, VC-4, VC-5, or VC-6)

Barge Loading

24. The following additional requirements apply to barge loading:

A. Flanged connections shall be used for all loading operations

B. Unless otherwise specified in this permit, all vapors associated with negative pressure loading of inland barges as allowed under USCG regulations with liquids having a vapor pressure greater than or equal to 0.50 psia at 95°F shall be routed through a vacuum-assisted collection system as specified below. Flanged connections shall be used for all loading operations.

(1) Barges shall not be loaded unless the vapor collection system is properly connected and the entire collection system is working as designed.

(2) A blower system shall be installed to produce a vacuum in the inland barges during all loading operations. A pressure/vacuum measurement device shall be installed as close as possible to the vessel's vapor return port to continuously monitor and record (at least once every 6 minutes) the vacuum pressure prior to the start of loading and while loading is taking place. Loading shall not take place unless there is a vacuum of at least 1.5 inch water column being maintained by the vacuum-assist vapor collection system while loading is occurring. The monitor shall be calibrated or have a calibration check performed on an annual basis to meet an accuracy of ± 5 percent of the vacuum being measured or ± 0.15 inches of water.

(3) Quality-assured (or valid) data must be generated when barge loading is occurring. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that barge loading is occurring over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

(4) Vacuum data shall be recorded every 6 minutes while loading is occurring.

Inerted Marine Vessels (ships)

25. The following additional requirements apply to loading of a VOC represented at 99% collection efficiency and has a vapor pressure equal to or greater than 0.50 pounds per square inch absolute (psia) under actual storage conditions onto inerted marine vessels (ships and ocean-going barges).

    A. Before loading, the owner or operator of the marine terminal shall verify that the marine vessel has passed an annual vapor tightness test as specified in 40 CFR §63.565(c) (September 19, 1995) or 40 CFR §61.304(f) (October 17, 2000) within the previous twelve months.

    B. The pressure at the vapor collection connection of an inerted marine vessel must be maintained such that the pressure in a vessels' cargo tanks do not go below 0.20 pounds per square inch gauge (psig) or exceed 80% of the lowest setting of any of the vessel's pressure relief valves. The lowest vessel cargo tank or vent header pressure relief valve setting for the vessel being loaded shall be recorded. Pressure shall be continuously monitored while the vessel is being loaded. Pressure shall be recorded at fifteen-minute intervals.

    C. VOC loading rates shall be recorded during loading. The loading rate must not exceed the maximum permitted loading rate.

    D. During loading, the owner or operator of the marine terminal or of the marine vessel shall conduct audio, olfactory, and visual checks for leaks once every 8 hours for on-shore equipment and on board the ship.

        (1) If a liquid leak is detected during loading and cannot be repaired immediately (for example, by tightening a bolt or packing gland), then the loading operation shall cease until the leak is repaired.

        (2) If a vapor leak is detected by sight, sound, smell, or hydrocarbon gas analyzer during the loading operation, then a "first attempt" shall be made to repair the leak. Loading operations need not be ceased if the first attempt to repair the leak is not successful provided that the first attempt effort is documented by the owner or operator of the marine vessel and a copy of the repair log is made available to a representative of the marine terminal.

        (3) If the attempt to repair the leak is not successful and loading continues, emissions from the loading operation for that ship shall be calculated assuming a collection efficiency of 95%.

        (4) Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Leak Check

26. The following actions shall be taken prior to removing loading lines/hoses from marine vessels and shore facilities.

    A. After the transfer is complete, the loading line/hose shall be isolated at the connections to the marine vessel and the shore piping. Liquid shall be drained from the line/hose either by elevating it to allow it to drain by gravity into the vessel prior to isolation or pumping the liquid from the line back to the pipeline, or gravity drained to a sump when vessel elevations prevent gravity draining the dock line/hose into the vessel.

    B. The loading line/hose may be disconnected from the shore and/or marine vessel piping after the liquid has been removed from the loading line/hose. If it is necessary to empty the line/hose, any residual liquid in the line/hose shall be immediately drained directly into a sump. If the line/hose is not emptied, the open end(s) of the line/hose shall be immediately capped, plugged, or blinded to prevent leakage.

    C. After the loading line/hose has been removed from the vessel, the vapor return line shall be isolated and blinded to prevent leakage.

    The actions shall be documented as part of the loading procedure.

Truck loading

27. The following additional requirements apply to truck loading.

    A. The loading of liquids identified by this permit is limited to a maximum combined loading rate 160,000 gallons (3,810 barrels) per hour.

    B. The following requirements apply to loading of tank trucks with liquids having a vapor pressure greater than or equal to 0.50 psia.

        (1) Each tank truck shall pass vapor-tight testing every 12 months using the methods described in Title 40 Code of Federal Regulations Part 63 (40 CFR 63), Subpart R. The permit holder shall not allow a tank truck to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the tank truck last passed the leak-tight test required by this condition and the identification number of the tank truck.

        (2) Emissions shall be vented to the Truck Loading Vapor Combustor (EPN TVC-1).

28. The following requirements apply to transfers of propane and sour water into pressurized trucks and transfers of butane from pressurized railcars.

    A. Transfer racks shall be designed such that the total volume of each component to be disconnected and vented to the atmosphere following transfer to/from any transport vessel, including adapters, hoses, fittings, valves or couplings, does not exceed 27 cubic centimeters.

B. The number of loading disconnects from loading trucks with propane is limited to 20 truck disconnects per hour and 4000 truck disconnects per year. The number of loading disconnects from loading railcar with butane is limited to 10 railcar disconnects per hour and 2100 railcar disconnects per year (EPN SG FUG). A record of disconnects during the previous calendar month and the past consecutive 12-month period shall be kept and made available upon request.

C. Emissions from loading trucks with sour water shall be vapor balanced from the truck back to the sour water tank (FIN T-851) such that there are no emissions to the atmosphere

D. Each truck shall be leak-checked and certified within the past 12 months in accordance with 49 CFR 180.407 Department of Transportation (DOT), for pressure tank trucks rated at 15 psig or greater. The permit holder shall not allow a tank truck to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the tank truck last passed the leak-tight test required by this condition and the identification number of the tank truck. This information shall be recorded for each truck loaded.

E. Each railcar shall be leak-checked and certified within the past 12 months in accordance with Class DOT-111AW or Class DOT-115AW testing. The permit holder shall not allow a railcar to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the railcar last passed the leak-tight test required by this condition and the identification number of the railcar. This information shall be recorded for each railcar loaded.

29. The permit holder shall maintain and update a monthly emissions record which includes calculated emissions of VOC from all loading operations over the previous rolling 12-month period. The record shall include the loading spot, type of vessel loaded, control method used, quantity loaded in gallons, name of the liquid loaded, vapor molecular weight, liquid temperature in degrees Fahrenheit, liquid vapor pressure at the liquid temperature in psia, liquid throughput for the previous month and rolling 12 months to date. Records of VOC temperature are not required to be kept for liquids loaded from unheated tanks which receive liquids that are at or below ambient temperatures. Emissions shall be calculated using the methods identified in the application, PI-1 dated July 14, 2017.

30. All rail cars in butane service shall be depressurized to the Rail Car Flare (EPN FL-2). No more than the combined rate of 48,000 standard cubic feet (scf) of railcar vapors shall be purged per hour to the flare. No more than 18.91 million standard cubic feet (mmscf) on a 12-month rolling average shall be purged to the flare.

After the railcar has been depressurized, all hatches and connections shall remain closed such that there are no uncontrolled emissions vented to the atmosphere from the railcar.

Compliance with the maximum flow limit shall be demonstrated by recording the average hourly rate of the vent stream flow during all periods that railcars are degassed to the flare. Flow shall be determined using the flow monitor as required by Special Condition 34. The permit holder shall also maintain a record of total flow volume from depressurizing railcars to the flare. The record shall be updated monthly and kept on a 12-month rolling basis.

The record shall include the monthly flow to the flare and all parameters used to determine it.

Process Vents

31. Particulate matter shall not exceed 0.01 grain per dscf of air and/or nitrogen from the Catalyst Lock Hopper Vent (EPN CCR-V2). There shall be no visible emissions exceeding 30 seconds in any six-minute period as determined using U.S. Environmental Protection Agency (EPA) Test Method 22.

    The vents covered by this condition shall not operate unless control devices and associated equipment are maintained in good working order and operating. All vents will be inspected for visible emissions once per day and a spare-parts filter inventory will be maintained on site. Records shall be maintained of all inspections and maintenance performed.

    The differential pressure across each filter in the nitrogen return line shall be continuously monitored and be recorded during all periods that fresh catalyst is added to the Lock Hopper (FIN D-302). The pressure drop shall be at least 1.0 inch water column and shall not exceed 5 inches water column.

    Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within ±3%.

    Quality assured (or valid) data must be generated when the Continuous Catalytic Reformer (CCR) is operating except during the performance of a daily zero check. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the CCR operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

32. Vent emissions from blowdown of the Debutanizer Overhead Drum (FIN D-003) and the Crude Tower Overhead Drum (FIN D-001) shall be routed to the Main Flare (EPN PK-712).

Control Devices

33. A. Each marine vapor combustor (EPNs VC-1 through VC-6) shall achieve 99.9% control of the VOC directed to it. This shall be ensured by maintaining the temperature in, or immediately downstream of, the combustion chamber above 1400 °F prior to the initial stack test performed in accordance with Special Condition No. 41. Following the completion of that stack test, the six-minute average temperature shall be maintained above the minimum one-hour average temperature but below the maximum one-hour average temperature maintained during the last satisfactory stack test:

B. The truck loading vapor combustor (EPN TVC-1) shall achieve 99.5% control of the VOC directed to it. This shall be ensured by maintaining the temperature in, or immediately downstream of, the combustion chamber above 1400 °F prior to the initial stack test performed in accordance with Special Condition No. 41. Following the completion of that stack test, the six-minute average temperature shall be maintained above the minimum one-hour average temperature but below the maximum one-hour average temperature maintained during the last satisfactory stack test.

C. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature monitor shall be installed, calibrated or have a calibration check performed at least annually, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ±2 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

Quality assured (or valid) data must be generated when the VCU is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the VCU operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Each vapor combustor shall be operated with no visible emissions and have a constant pilot flame during all times waste gas could be directed to it. The pilot flame shall be continuously monitored by a thermocouple, an infrared monitor, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated or have a calibration check performed at a frequency in accordance with, the manufacturer's specifications.

D. Fuel gas combusted at these facilities shall be sweet natural gas containing no more than 0.20 grains of total sulfur per 100 dry standard cubic feet. The natural gas shall be sampled every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement. Records of the volume of supplemental natural gas used during the previous calendar month and the past consecutive 12 months for each vapor combustor shall kept.

34. Flares authorized by this permit shall be designed and operated in accordance with the following requirements. Unless otherwise specified, all requirements of this condition shall apply during periods that regulated material may be vented to the flare.

    A. The flare systems shall be designed such that the combined vent gas, assist air, and/or total steam to each flare meets the 40 CFR § 63.670 specifications for minimum combustion zone net heating value, the minimum dilution parameter net heating value, and maximum tip velocity at all times that emissions may be directed to the flare for more than 15 minutes.

       Flared gas actual exit velocity, vent gas net heating value, and flared gas combustion zone net heating value shall be determined in accordance with 40 CFR 63.670(k), 63.670(l), and 63.670(m) on a 15-minute block average and recorded at least once every 15 minutes.

       If perimeter assist air is used, the dilution parameter net heating value shall be determined in accordance with 40 CFR 63.670(n) on a 15-minute block average recorded at least once every fifteen minutes.

    B. The flares shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple, infrared monitor, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated or have a calibration check performed at a frequency in accordance with, the manufacturer's specifications.

    C. Flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours, demonstrated and recorded per the requirements of 63.670(h).

    D. The permit holder shall install flow monitors and calorimeters that continuously measure, calculate and record the total volumetric vent stream flow rate (including waste gas, purge gas, supplemental gas, and sweep gas) and Btu content in the flare header or headers to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream such that the total vent stream to the flare is measured and analyzed.

       If one or more gas streams that combine to comprise the total flare vent gas flow are monitored separately for net heating value and flow, the 15-minute block average net heating value shall be determined separately for each measurement location and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

       If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the total volumetric flow rate of assist air and/or assist steam used with the flare.

If pre-mix assist air and/or perimeter assist are used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and/or perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

Ambient air provided to steam assisted flares by a steam induction ring is exempt from the perimeter assist monitoring requirements.

The volumetric flow of assist air provided to steam assisted flares through steam induction tubes shall be determined as specified by the vendor.

The monitors shall be calibrated or have a calibration check performed on an annual basis and as specified in Table 13 of the appendix to 40 CFR 63, Part CC to meet the following accuracy specifications: the vent flow monitor shall be ±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second) ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second), all other gas flow monitors shall be ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute) whichever is greater, temperature monitor shall be ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater, and pressure monitor shall be ±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater. For purposes of this permit, a calibration check means, at a minimum, using a second device or method to verify that the monitor is accurate as specified in the permit.

Calorimeters shall have an accuracy of at least ±2% of span and be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in Table 13 of the appendix to 40 CFR 63, Part CC, to continuously measure and record the net heating value of the vent gas sent to the flare, in British thermal units/standard cubic foot of the gas.

E. Quality assured (or valid) data must be generated during periods that the flare is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the flare operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

F. Hourly mass emission rates of NOx and CO shall be determined and recorded using the net heating value of the gas combusted in the flare calculated per Special Condition 34.D and emission factors used in the application PI-1 dated July 14, 2017.

35. Any gas vented to a flare for control shall not exceed a H2S concentration of 162 ppmv on a 1-hour rolling basis. The holder of this permit shall install a continuous H_2S monitoring system in accordance with the fuel sulfur monitoring requirements of 40 CFR §60.107a(2). The monitor shall be installed in a location as close to the flare header as possible and in a location prior to introduction of any supplemental fuel or purge gas.

36. The venting of any halogenated compounds to a flare is not authorized by this permit.

37. The following requirements apply to the Acid Injection Tank Scrubber (EPN SM-823-T1)

    A. The Acid Injection Tank Scrubber (EPN SM-823-T1) shall operate with no less than 99 percent removal efficiency for HCL during normal operations and while performing MSS on the tank.

    B. The minimum liquid flow to the absorber (gal/min) shall be no lower than that recommended by the manufacturer. The circulation rate shall be monitored and recorded at least once an hour.

    C. The flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

       Quality assured data must be generated when storage tank the scrubber SM-823-T1 is operating except during the performance of a daily zero check. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the storage tank operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

    D. The scrubbing solution shall be maintained at or above (or below) the manufacturer's recommended pH. The pH shall be continuously analyzed and recorded at least once a minute. Each monitoring device shall be cleaned with an automatic cleaning system, or cleaned weekly using hydraulic, chemical, or mechanical cleaning. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least weekly, whichever is more frequent, and shall be accurate to within ± 0.5 pH unit.

       Quality assured data must be generated when scrubber SM-823-T1 is operating except during the performance of a daily zero check. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the scrubber SM-823-T1 operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Continuous Catalytic Reformer (CCR)

38. The CCR Regeneration Vent (EPN CCR-V1) is subject to the following requirements:

    A. Emissions of total organic compounds (TOC) or nonmethane TOC shall not exceed a concentration of 20 ppmv (dry basis as hexane), corrected to 3 percent oxygen on a 1-hour average basis.

    B. Uncontrolled emissions of hydrogen chloride (HCl) shall be reduced by 99 percent by weight or to a concentration of 10 ppmv (dry basis), corrected to 3 percent oxygen on a 1-hour average basis.

    C. Uncontrolled emissions of chlorine (Cl_2) by 99 percent by weight or to a concentration of 2 ppmv (dry basis), corrected to 3 percent oxygen on a 1-hour average basis.

39. The CCR regeneration vent shall be controlled by a scrubbing system (EPN CCR-V1) consisting of two scrubbers in series (caustic wash upstream of packed bed absorber) and shall be operated in accordance with the following requirements:

    A. The minimum liquid flow to the packed bed absorber and caustic wash, in gallons per minute (gpm) shall that recommended by the manufacturer prior to the first stack test performed in accordance with Special Condition 41. After the first satisfactory stack test, the flow shall be at least equal to that maintained during the most recent satisfactory stack test. The circulation rate shall be continuously monitored and recorded at least once every six minutes.

    B. The flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

       Quality assured (or valid) data must be generated when the CCA reformer is operating except during the performance of a daily zero check. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the CCA reformer operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

    C. The scrubbing solution of the caustic wash shall be maintained at or above (or below) the manufacturer's recommended pH prior to the initial stack test performed in accordance with Special Condition 41. After the stack test has been completed, the pH shall be at or above the average pH maintained during the last satisfactory stack test. The pH shall be continuously analyzed and recorded at least once a minute. Each monitoring device shall be cleaned with an automatic cleaning system, or cleaned weekly using hydraulic, chemical, or mechanical cleaning. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least weekly, whichever is more frequent, and shall be accurate to within ± 0.5 pH unit.

Quality assured (or valid) data must be generated when the (facility generating emissions) is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the (facility generating emissions) operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgement and the methods used recorded.

D. The exhaust from the scrubber shall be continuously monitored using a CEMS for VOC, HCl, and Cl_2. The CEMs shall comply with the requirements of Special Condition 43.

40. The following requirements apply to capture systems for the flares, marine loading vapor combustor, and truck loading vapor combustor.

A. If used for particulate control, complete either of the following once a year

1. Inspect any fan and verify proper operation and inspect the capture system to verify there are no cracks, holes, tears, and other defects once a year; or

2. Verify there are no fugitive emissions escaping from the capture system by performing a visible emissions observation for a period of at least six minutes in accordance with 40 CFR Part 60, Appendix A, Test Method 22.

B. If used to control pollutants other than particulate, either:

1. Conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system; or

2. Once a year, verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

C. The control device shall not have a bypass.

If any of the above inspections is not satisfactory, the permit holder shall promptly take necessary corrective action

Initial Demonstration of Compliance

41. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the Marine VCUs (EPNs VC-1 through VC-6), the Truck Loading VCU (EPN TVC-1, and from heater and reboiler Facility Identification Numbers (FINs) H-001, H-002, H-101, H-201, H-202, H-203, H-204, H-205, H-101, H-401, H-402, M-801 (EPNs H-001, H-CCR12, H-CCR34, H-002, H-CCR5, H-401, H-402, and M-801), and the continuous catalytic reformer (CCR) regeneration vent (WPN CCR-V1) to demonstrate compliance with the emission limits and control device DRE or removal efficiency as specified in Special Conditions 17 and 18, 33, 38, and the MAERT. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing

operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and the U.S. EPA Reference Methods.

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for 40 CFR Part 60 testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

1. Proposed date for pretest meeting.
2. Date sampling will occur.
3. Name of firm conducting sampling.
4. Type of sampling equipment to be used.
5. Method or procedure to be used in sampling.
6. Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.
7. Procedure/parameters to be used to determine worst case emissions;

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Air contaminants emitted from the Marine Loading VCUs (EPNs VC-1 through VC-6) and the Truck Loading Vapor Combustor (EPN TVC-1) to be tested for include (but are not limited to) VOC, NOx, and CO. Testing shall also include O_2.

Air contaminants emitted from the heater and reboiler FINs H-001, H-002, H-201, H-202, H-203, H-204, and M-801s (EPNs H-001, H-002, H-CCR12, H-CCR34, M-801), to be tested for include (but are not limited to) NOx, CO, PM, SO_2, and NH_3. Testing shall also include O_2. For combustion units that share a common stack, testing shall be performed for each individual heater and reboiler. If individual testing is not possible while the unit is operating, then testing will be performed while the combustion units sharing he stack are operating simultaneously and the results compared to the emissions limits common to the stack.

Air contaminants emitted from the heater and reboiler FINs H-101, H-205, H-401, H-402 (EPNs H-101, H-CCR5, H-401, and H-402) to be tested for include (but are not limited to) NOx, CO, and SO_2. Testing shall also include O_2.

Air contaminants emitted from the regeneration gas loop vent (EPN CCR-V1) to be tested for include (but are not limited to) HCL, Chlorine (Cl2), and VOC (as Hexane).

C. Sampling shall occur within 60 days after achieving the maximum operating rate, but no later than 180 days after initial start-up of the facilities (or increase in production, as appropriate) and at such other times (identify the need for any periodic sampling here) as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

D. Operating parameters during sampling.

1. Sampling of emissions from each marine loading vapor combustor (EPNs VC-1 through VC-6) shall be conducted for each of the following scenarios:

   a. Sampling shall be performed while venting emissions from loading 3 barges with gasoline at the maximum loading rate of 15,000 bbls/hr (5,000 bbls/barge) to the vapor combustor.

   b. Sampling shall be performed at the maximum temperature that the vapor combustor will be operated. (NO_x only).

2. Sampling of emissions from the truck loading vapor combustor (EPN TVC-1), shall be conducted shall be conducted for each of the following scenarios:

   a. Sampling shall be performed while loading gasoline at the maximum loading rate of 3810 bbls/hr.

   b. Sampling shall be performed at the maximum temperature that the vapor combustor will be operated. (NO_x only).

3. Sampling of emissions from heaters and reboilers shall occur while the combustion device is operating at the maximum firing rate while firing with fuel gas. The H_2S content of the fuel gas as well as flow of fuel gas shall be monitored during the test. At the completion of the stack test, a mass balance shall be performed using the results of the stack test along with calculations using the H_2S content and fuel flow rate to determine the amount of additional sulfur compounds that may be present in the fuel gas. The presence of additional sulfur compounds shall be recorded and included in calculations used to determine compliance with short-term and annual SO_2 emissions authorized in the MAERT.

4. For the CCR regeneration vent (EPN CCR-V1), sampling shall be conducted at the maximum CCR operating rate.

These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the

TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the loading rate or firing rate (as applicable) is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

B. Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled “Chapter 14, Contents of Sampling Reports” of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the appropriate TCEQ Regional Office.

One copy to each local air pollution control program.

C. Sampling ports and platform(s) shall be incorporated into the design of each heater/boiler stack and each control device stack according to the specifications set forth in the attachment entitled “Chapter 2, Stack Sampling Facilities” of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

42. The permit holder shall install, calibrate, and maintain a CEMS to measure and record the in-stack concentrations of the following compounds from the indicated sources:

A. Heater EPNs H-001, H-002, H-CCR12, H-CR34, and M-801: NOx, CO, and O_2.

B. CCR regeneration vent EPN CCR-V1: HCL, Cl_2, VOC, and O_2.

43. All CEMS monitoring systems shall meet the following requirements:

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

1. The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

2. Unless Appendix F is otherwise required by NSPS, state law or regulation, or permit or approval, in lieu of the requirements of 40 CFR Part 60 Appendix F 5.1.1, 5.1.3, and 5.1.4, the permit holder may conduct:

   a. either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every three (3) years; and

   b. Cylinder Gas Audit (CGA) each calendar quarter in which the RAA or RATA is not performed.

The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is **not** required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months

All CGA exceedances of ±15 percent accuracy indicates that the CEMS is out of control

C. The monitoring data shall be reduced to one-hour average concentrations, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be used with the fuel flow data and fuel heating value data to determine and record the hourly furnace HHV firing rate in MMBtu/hr, and the exhaust flow rate by Method 19 in 40 CFR Part 60, Appendix B, to show and record compliance with the hourly operating limits in Special Conditions 16 and the MAERT short term lb/hr allowable limits. The hourly emissions shall be combined and recorded to show compliance with the rolling 12 month operating and MAERT limits

Fuel flow shall be determined in accordance with Paragraph D of this condition. Fuel heating value shall be determined as the most recent value determined as required by Special Condition No. 16.

D. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for each boiler and each heater. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

E. All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

F. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing

G. Quality-assured (or valid) data must be generated when the heater is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the heater operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgement and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

44. Compliance with the NH_3 emission limits of Special Condition 17.A shall be continuously demonstrated using one of the following options:

A. Install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NH_3.

B. Install and operate two NO_x CEMS, one located upstream of the Selective Catalytic Reduction (SCR) system and the other located downstream of the SCR system, which are used in association with NH_3 injection rate and the following calculation procedure to estimate NH_3 slip.

NH_3 slip @O2, ppmvd = $[(a / b \times 10^6) - c] \times d$

where:

a = ammonia injection rate (lb/hr)/17 (lb/lb-mole);

b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb-mole);

c = change in measured NO_x concentration across catalyst (ppmvd at reference oxygen); and

d = appropriate correction factor.

correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack sampling for ammonia during an initial demonstration of compliance required by this chapter and using the methods specified in §117.8000 of this title (relating to Stack Testing Requirements)

All CEMS specified in this condition must meet the requirements of Special Condition No. 43. Quality-assured (or valid) data must be generated when gas is directed to the SCR system. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time that gas is directed to the SCR system over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Equipment Leaks

Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

45. Except as provided for in the special condition 46 of this permit, the following requirements apply to the above-referenced equipment:

    A. The requirements of paragraphs F and G shall not apply (1) where the VOC content is less than 10 weight percent, (2) the methane content is less than 10 weight percent, or (3) the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

       The exempted components may be identified by one or more of the following methods:

       1. piping and instrumentation diagram (PID);
       2. a written or electronic database or electronic file;
       3. color coding;
       4. a form of weatherproof identification; or
       5. designation of exempted process unit boundaries.

    B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

    C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

    D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request.

       The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

1. a cap, blind flange, plug, or second valve must be installed on the line or valve;

   or

2. the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72-hour period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the

process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all process drains shall be monitored with an approved gas analyzer at least annually. Process drains found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking shall be tagged and repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

H. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

I. Damaged or leaking valves or connectors found to be emitting VOC or methane in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

J. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next

scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

K. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator’s log or equivalent.

L. Alternative monitoring frequency schedules of 30 TAC " 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

M. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

46. Piping, Valves, Pumps, and Compressors in Ammonia (NH_3) and H_2S Service

A. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made once per shift.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

1. Isolate the leak.

2. Commence repair or replacement of the leaking component.

3. Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

Cooling Towers

47. The cooling tower (EPN: CT-801) shall be operated in accordance with the following requirements:

A. The VOC associated with cooling water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method.

B. Cooling tower water VOC concentrations above 0.08 ppmw indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs.
Emissions from the cooling tower are not authorized if the VOC concentration of the water returning to the cooling tower exceeds 0.8 ppmw. VOC concentrations above 0.8 ppmw are not subject to extensions for delay of repair under this permit condition.

C. The results of the monitoring, cooling water flow rate, and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly VOC emissions. The rolling 12-month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12-month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the 2 VOC monitored results

D. The cooling tower shall be operated and monitored in accordance with the following:

(1) The cooling tower shall be equipped with drift eliminators that achieve a maximum drift of no more than 0.0005 percent. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

(2) Total dissolved solids (TDS) shall not exceed 3,500 parts per million by weight (ppmw). Average TDS on a rolling 12-month basis shall not exceed 2,500 parts per million by weight (ppmw). Dissolved solids in the cooling water drift are considered to be emitted as PM, PM10, and PM2.5 as represented in the permit application calculations.

(3) Cooling towers shall be analyzed for particulate emissions using one of the following methods:

a. Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or

b. TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per μmho/cm or ppmw/siemens). The ratio of TDS-to-conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or

c. TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation factor established for each cooling tower. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using (D)(3)(b) provided the highest ratio is not more than 10% larger than the smallest ratio.

d. The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.

(4) Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

a. The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, or SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection,and transferred to a laboratory area for analysis.

b. The analysis method for conductivity shall be either ASTM D1125-95A (field or routine laboratory testing) or ASTM D1125-95B (continuous monitor). The analysis may be conducted at the sample site or with a calibrated process conductivity meter. If a conductivity meter is used, it shall be calibrated at least annually. Documentation of the method and any associated calibration records shall be maintained.

c. Alternate sampling and analysis methods may be used to comply with D(3) and D(4) with written approval from the TCEQ Regional Director.

d. Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

(5) Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, the design drift rate the droplet size distribution represented in the application, and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

E. The actual cooling water circulation rate shall be measured at least hourly. Measurements shall be reduced to an hourly average and recorded for use in emission calculations.

Wastewater Systems

48. Process wastewater drains shall be equipped with water seals or equivalent; lift stations, manholes, junction boxes, any other wastewater collection system components, and conveyance that are upstream from the CPI surge pit shall be equipped with a closed vent system that routes all organic emissions from each sump within the system to a Carbon Adsorption System (CAS) meeting the requirements of Special Condition 55.

    Water seals shall be checked by visual or physical inspection quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls. Water seals shall be restored as necessary within 24 hours. Records shall be maintained of these inspections and any corrective actions taken.

49. The daily wastewater flow into the wastewater treatment plant shall be monitored and recorded. The rolling 12-month wastewater flow shall be totaled on a monthly basis.

50. The minimum mixed liquor total suspended solids (MLSS) concentration in the aeration basins on a daily average basis shall not be less than 2,000 mg/L. The MLSS concentration is the arithmetic average of all samples collected during the 24-hour period. The MLSS concentrations shall be monitored and recorded daily using Method 160.2 (Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020 or Method 2540D (Standard Methods of the Examination of Water and Wastewater, 18th Edition, American Publ8ic Health Association)

51. Wastewater treatment plant emissions shall be estimated every month using the following procedure.

    A. The permit holder shall sample the wastewater prior to the CPI separator surge pit monthly to determine the concentrations of all air contaminants. Sampling locations, sampling procedures, test methods and calculations shall be as follows:

        (1) The sampling locations shall be at the inlet to CPI separator surge pit;

        (2) Sampling procedures shall be as specified in the TPDES permit applicable to the site. A copy of the TPDES permit and any precedent application representations shall be submitted for inclusion in the file for this permit prior to the start of operation of the facilities covered by this permit;

        (3) Test methods shall include EPA SW-846 method 8260B. Additional test methods shall be proposed by the holder of the permit and are subject to review and approval by the Executive Director; and

        (4) Emission calculations shall be as specified in permit application (PI-1 dated July 13, 2017).

The influent wastewater flow rates shall be measured and recorded when a sample required by this condition is collected. Records of sampling results shall be maintained for all air contaminants.

52. The permit holder shall calculate short-term loading rate in terms of pounds per hour (lb/hr) and rolling 12-month loading rate in terms of tons per year (tpy) for each air contaminant. The measured concentrations of each speciated air contaminant shall be converted to an equivalent mass emission rate based upon the flow rates during the sample collection period using the calculation methods and assumptions in the permit application (PI-1 dated July 13, 2017).

53. The MLSS used in the emission calculation shall be either the minimum identified in Special Condition 50 or the measured concentration for the day the sampling required for this condition is completed. The short-term emission rate calculations for such air contaminants shall be based on the concentrations and flow rates measured during sampling. The rolling 12-month emission rate calculation for each air contaminant shall be based on the rolling 12-month average contaminant concentration and the rolling 12-month wastewater flow. All other inputs into the calculation shall match those in the permit application for that averaging period (worst case). Total VOC mass emission rates shall be calculated as the sum of the individual speciated VOC mass emission rates

54. Records of sampling location, sampling procedures, sample chain of custody forms, test methods, sampling results, calculated emission rates, and sample of calculations shall be maintained.

55. The CPI separator shall vent through a carbon adsorption system (CAS) consisting of at least two activated carbon canisters that are connected in series.

    A. The CAS shall be sampled daily to determine breakthrough of volatile organic compounds (VOC). Sampling shall be performed during periods that waste water is passing through the CPI separator.

    B. The VOC sampling and analysis shall be performed using an instrument with a flame ionization detector (FID), or a TCEQ-approved alternative detector. The instrument/FID must meet all requirements specified in Section 8.1 of EPA Method 21 (40 CFR 60, Appendix A). Sampling and analysis for VOC breakthrough shall be performed as follows:

        1. Immediately prior to performing sampling, the instrument/FID shall be calibrated with zero and span calibration gas mixtures. Zero gas shall be certified to contain less than 0.1 ppmv total hydrocarbons. Span calibration gas shall be propane at a concentration within ± 10 percent of 100 ppmv, and certified by the manufacturer to be ± 2 percent accurate. Calibration error for the zero and span calibration gas checks must be less than ± 5 percent of the span calibration gas value before sampling may be conducted.

        2. The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sample ports or connections

must be designed such that air leakage into the sample port does not occur during sampling.

3. During sampling, data recording shall not begin until after two times the instrument response time. The VOC concentration shall be monitored for at least 5 minutes, recording 1-minute averages, during operation of the CPI.

C. Breakthrough shall be defined as the highest 1-minute average measured VOC concentration at or exceeding 100 ppmv. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within 24 hours. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

D. Records of the CAS monitoring maintained at the plant site, shall include (but are not limited to) the following:

1. Sample time and date.

2. Monitoring results (ppmv).

3. Corrective action taken including the time and date of that action.

4. Process operations occurring at the time of sampling.

E. Alternate monitoring or sampling requirements that are equivalent or better may be approved by the TCEQ Regional Manager. Alternate requirements must be approved in writing before they can be used for compliance purposes

Intermittent Sources

56. A. Each emergency generator and each emergency firewater pump (EPNs GEN-1, GEN-2, GEN-3, GEN-4, FWP-1, and FWP-2) is limited to no more than 52 hours per rolling 12- month period of non-emergency operation. Records of the hours of operation kept on a monthly and rolling 12-month basis shall be maintained by the holder of this permit

B. Each generator or firewater pump must be equipped with a non-resettable runtime meter.

C. The engine(s) shall be operated and maintained according to the manufacturer's emission-related written instructions

D. Fuel for engines shall include ultra-low sulfur diesel containing no more than 15 ppm sulfur by weight.

E. Records of fuel delivery indicating date and quantity of fuel delivered shall be maintained by the holder of this permit. If the fuel is designated ultra-low sulfur

diesel (ULSD) on the receipt, this is acceptable as showing compliance with sulfur limitations of this permit. Otherwise, keep records of the sulfur content of the fuel based on receipts or chemical analyses.

Odor Control

57. Odorous emissions from this facility must not cause or contribute to a condition of "air pollution" as defined in Section 382.003(2) of the Texas Clean Air Act. If a condition of odorous air pollution develops, additional abatement measures acceptable to the Executive Director must be implemented immediately upon notification.

    If a representative of the TCEQ or any other air pollution control agency having jurisdiction over this facility confirms outside the site nuisance odors from any sources inside the site, immediate corrective action shall be initiated to abate the nuisance odor or repair malfunctioning equipment, and additional control measures may be required.

Miscellaneous Provisions

58. Prior to the start of operations of any facility authorized by this by this permit that was not constructed prior to the issuance of this permit, the permit holder shall obtain a permit alteration or permit amendment as applicable which updates the permit representations and these Special Conditions as follows:

    A. Provide the as-built process for sampling liquids and process gases from drawing of the sample to reintroduction of the sample back into the process or sample disposal Special Conditions for demonstrating BACT and compliance with emissions from product sampling in the permit.

    B. Route all emissions from the wastewater equalization and injected air floatation to a control device with a minimum control efficiency of 99%.

Planned Maintenance, Startup and Shutdown (MSS)

59. This permit authorizes the emissions from the facilities authorized by this permit for the planned maintenance, startup, and shutdown (MSS) activities summarized in the table at Paragraph A.

    Additionally, this permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, portable control devices identified in Special Condition 71 and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities listed in this Attachment, and (c) does not operate as a replacement for an existing authorized facility.

A. MSS Activity Summary.

Facilities	Description	Emissions Activity
all process units/components containing liquids having a vapor pressure greater than or equal to 0.50 psia	unit shutdown/ depressurize/degas	vent to control
all process units/components containing liquids having a vapor pressure greater than or equal to 0.50 psia	Uncontrolled Venting	vent to atmosphere
all process units/components with a volume greater than 2 cubic feet containing liquids having a vapor pressure less than 0.50 psia	unit shutdown/ depressurize/degas	vent to control
all process units/components with a volume greater than 2 cubic feet containing liquids having a vapor pressure less than 0.50 psia	Uncontrolled Venting	vent to atmosphere
all process units/components with a volume less than or equal to 2 cubic feet containing liquids having a vapor pressure less than 0.50 psia	unit shutdown/ depressurize	vent to atmosphere
all process units/components	Drain residual liquid	vent to atmosphere
all process units/components	Opening	vent to atmosphere
all process units/components with a volume less than or equal to 2 cubic feet containing liquids having a vapor pressure greater than or equal to 0.50 psia	unit startup	vent to atmosphere
all process units/components containing liquids having a vapor pressure greater than or equal to 0.50 psia	unit startup	vent to control

Facilities	Description	Emissions Activity
all process units/components with a volume greater than 50 cubic feet containing liquids having a vapor pressure less than 0.50 psia	unit startup	vent to control
all process units with a volume less than or equal to 50 cubic feet containing liquids having a vapor pressure less than 0.50 psia	unit startup	vent to atmosphere
all fixed roof tanks containing liquids having a vapor pressure greater than or equal to 0.50 psia	unit shutdown/ degas / clean	vent to control
all fixed roof tanks containing liquids having a vapor pressure less than 0.50 psia	unit shutdown/ degas / clean	vent to atmosphere
all floating roof tanks	tank roof landing operations (standing idle, degassing, cleaning, filling)	Vent to control
all floating roof tanks	Uncontrolled venting	Vent to atmosphere
Vacuum Trucks	Draining/clearing	Vent to control
Frac Tanks	Temporary storage	Vent to control
See Paragraph C	Miscellaneous Inherently Low Emitting Activities	Vent to atmosphere

B. Routine Component Maintenance Activities

Pump repair/replacement

Fugitive component (valve, pipe, flange) repair/replacement

Compressor repair/replacement

Heat exchanger repair/replacement

C. Inherently Low Emitting Activities

Activity	Emissions				
	VOC	NO_x	CO	PM	H_2S/SO_2
Engine Maintenance	x				
Aerosol Cans	x				
Calibration of analytical equipment	x				
Lubricants/solvents	x				
Instrumentation/analyzer maintenance	x				
Replacement of analyzer filters and screens	x				

60. Special Condition 59.C identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in 59.C shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in 59.C must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

Routine maintenance activities, as identified in Special Condition No. 59.B may be tracked through the work orders or equivalent. Emissions from activities identified in Special Condition No. 59.B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

Maintenance activities authorized in Special Condition 59.B are applicable to facilities with volumes less than or equal to 50 cubic feet. Work orders shall be divided into categories of facilities with volumes less than or equal to 2 cubic feet and those facilities with volumes greater than 2 cubic feet but less than or equal to 50 cubic feet.

The performance of each planned MSS activity not identified in Special Condition No. 59.B or 59.C and the emissions associated with it shall be recorded and include at least the following information:

A. the process unit at which emissions from the MSS activity occurred, including the emission point number and common name of the process unit;

B. the type of planned MSS activity and the reason for the planned activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

D. the date and time of the MSS activity and its duration;

E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

Process Units and Facilities

61. Process units and facilities, with the exception of those identified in Special Condition Nos. 64, 65, 68 and Special Condition 59.C shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. Unless otherwise specified in this condition, process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains a liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

Process units and facilities with volumes greater than 50 cubic feet shall be depressurized at a rate not to exceed 127 standard cubic feet per minute (scfm).

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel or closed liquid recovery system unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F or if the facility(s) undergoing MSS have a volume greater than 50 cubic feet and the VOC partial pressure is less than or equal to 0.50 psia but greater than 0.011 psia at the normal process temperature or 95°F, the facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through a control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC concentration following controlled depressurization. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from

controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

1. The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition No. 62. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. If there is not a connection (such as a sample, vent, or drain valve) available from which a representative sample may be obtained, a sample may be taken upon entry into the system after degassing has been completed. The sample shall be taken from inside the vessel so as to minimize any air or dilution from the entry point.

2. Controlled degassing shall continue until one of the following conditions is met.

   (1) If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F and the facility(s) have a volume less than or equal to 50 cubic feet, the facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than or equal to 5,000 ppmv.

   (2) If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F and the facility(s) have a volume greater than 50 cubic feet, the facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than or equal to 4,000 ppmv.

   (3) If the VOC partial pressure is less than or equal to 0.50 psia but greater than 0.10 psia at the normal process temperature or 95°F and the facility(s) have a volume greater than 50 cubic feet, the facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than or equal to 750 ppmv.

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

   1. It is not technically practicable to depressurize or degas, as applicable, into the process.

   2. There is not an available connection to a plant control system (flare).

   3. There is no more than 50 lb of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Paragraph E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order or equivalent for those planned MSS activities identified in Special Condition No. 59.B.

F. Emissions from placing the following process units and facilities back in service (filling/priming) shall be vented to a control device with a minimum VOC destruction efficiency of 98%. The rate of refill/priming shall not exceed 9350 gallons per hour.

1. Emissions from filling process units and facilities with liquids having a vapor pressure greater than or equal to 0.50 psia at the normal process temperature or 95°F.

2. Emissions from filling facilities having a volume greater than 50 cubic feet with liquids having a vapor pressure less than 0.50 psia at the normal process temperature or 95°F.

62. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR 60, Appendix A) with the following exceptions:

1. The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor (RF) of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate RF shall be recorded. If the RF of the VOC (or mixture of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows:

   VOC Concentration = Concentration as read from the instrument*RF

   In no case should a calibration gas be used such that the RF of the VOC (or mixture of VOCs) to be monitored is greater than 5.0.

2. Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes, recording VOC concentration each minute. As an alternative the VOC concentration may be monitored over a five-minute period with an instrument designed to continuously measure concentration and record the highest concentration read. The highest measured VOC concentration shall be recorded and shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

1. The air contaminant concentration measured as defined in item (3) is less than 80 percent of the range of the tube and is at least 20 percent of the maximum range of the tube.

2. The tube is used in accordance with the manufacturer’s guidelines.

3. At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

   measured contaminant concentration (ppmv) < release concentration.

   Where the release concentration is:

   the maximum release concentration specified in the applicable special condition (ppmv) *mole fraction of the total air contaminants present that can be detected by the tube.

   The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

63. This condition applies only to piping and components subject to leak detection and repair monitoring requirements identified in this or other NSR permits. Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

A. a cap, blind flange, plug, or second valve must be installed on the line or valve; or

B. the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once by the end of the 72 hours period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

Floating Roof Storage Tanks

64. This permit authorizes emissions from floating roof storage tanks identified in Special Condition 6 during planned floating roof landings. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated in the MAERT. The following requirements apply to tank roof landings.

   A. At all times that the roof is resting on its leg supports, the tank emissions shall be controlled by a closed vent system and control device meeting the following specifications.

      1. The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

      2. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when the vapor space is directed to the control device. The vapor recovery system collection rate shall be no less than 100 cubic feet per minute when the tank is idle or the tank is being drained, and two times the fill rate when the tank is being refilled.

   Emissions shall be vented to a vapor combustor operated as required by Special Condition 71.B. The roof shall be landed on its lowest legs unless entry or inspection is planned.

   The requirements of this paragraph do not apply to uncontrolled degassing and/or ventilation conducted pursuant to paragraphs B–D of this Special Condition.

   B. After the tank has been completely emptied, the tank shall not be opened except as necessary to set up for degassing and cleaning. Controlled degassing of the vapor space under the landed roof shall be completed as follows:

      1. The following requirements apply to tanks where just prior to the landing event stored a liquid with a VOC partial pressure greater than or equal to 0.50 psia at 95°F

         a. For tanks where just prior to the landing event stored a liquid with a VOC partial pressure greater than or equal to 0.50 psia at 95°F, any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 5,000 ppmv.

         b. The maximum rate of mechanical ventilation during controlled degassing shall not exceed a combined rate of 280 cubic feet per minute per tank for tank EPNs T-250-1 through T-250-6 and 123 cubic feet per minute for all other internal floating roof tanks.

c. Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.074 psia.

2. A volume of purge gas equivalent to twice the volume of the vapor space under the floating roof must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration.

   For storage tanks where just prior to the landing event stored a liquid with a VOC partial pressure less than 0.50 psia at 95°F, the vapor space under the landed roof shall be degassed to a control device for a minimum of 4 tank volumes at a rate not to exceed 280 cubic feet per minute (cfm) for each tank.

   The measurement of purge gas volume shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition 62.

3. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

4. The vapor space under the floating roof shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design.

5. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

6. Uncontrolled venting of emissions to the atmosphere from the tank during post control degassing and sludge removal may occur at rates not to exceed the following provided Special Conditions 64.B(1), 64.B(2), and 64.D have been satisfied.

   a. 405 cfm during post control ventilation and sludge removal for tanks where just prior to the landing event stored a liquid with a VOC partial pressure less than 0.50 psia at 95°F

   b. 600 cfm per tank during uncontrolled ventilation for tanks where just prior to the landing event stored a liquid with a VOC partial pressure greater than or equal to 0.50 psia at 95°F.

c. 280 cfm per tank during sludge removal for tanks where just prior to the landing event stored a liquid with a VOC partial pressure greater than or equal to 0.50 psia at 95°F

C. The tank shall not be opened or ventilated without control, except as allowed by (1) below until one of the criteria in paragraph D of this condition is satisfied.

1. Minimize air circulation in the tank vapor space.

a. One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. Other manways or access points may be opened as necessary to remove or de-volatilize the remaining liquid. Wind barriers shall be installed at all open manways and access points to minimize air flow through the tank.

b. Access points shall be closed when not in use.

D. The tank may be opened without restriction and ventilated without control after all standing liquid has been removed from the tank or the liquid remaining in the tank has a VOC partial pressure of less than 0.02 psia. These criteria shall be demonstrated in one of the following ways:

1. Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

2. If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated.

a. Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A Appendix 1.

b. Take a representative sample of the liquid remaining in the tank and verify that the hexane soluble VOC concentration is less than 1000 ppmw using EPA method 1664.

c. Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify that the VOC concentration is less than 1000 ppmw through the procedure in Special Condition 62.

3. No standing liquid, verified through visual inspection.

The permit holder shall maintain records to document the method used to release the tank.

E. The maximum fill rate to refloat the roof shall not exceed 5000 bbls/hr per tank.

F. The occurrence of each roof landing and the associated emissions shall be recorded and the rolling 12-month tank roof landing emissions shall be updated on a monthly basis. These records shall include at least the following information:

1. the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

2. the reason for the tank roof landing;

3. for the purpose of estimating emissions, the date, time, and other information specified for each of the following events:

   a. the roof was initially landed,

   b. all liquid was pumped from the tank to the extent practical,

   c. start and completion of controlled degassing, and total volumetric flow,

   d. all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,

   e. if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

   f. refilling commenced, liquid filling the tank, and the volume necessary to float the roof; and

   g. tank roof off supporting legs, floating on liquid;

4. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between events c and g with the data and methods used to determine it. The emissions associated with roof landing activities shall be calculated using the methods described in Section 7.1.3.2 of AP-42 "Compilation of Air Pollution Emission Factors, Chapter 7 - Storage of Organic Liquids" dated November 2006 and the permit application.

<u>Fixed Roof Storage Tanks</u>

65. Unless otherwise specified in this condition, fixed roof storage tanks shall comply with the following requirements during MSS.

A. If the VOC partial pressure of the liquid previously stored in the tank is greater than 0.50 psi at 95°F, controlled degassing of the vapor space shall be completed as follows:

1. Any gas or vapor removed from the vapor space must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 4,000 ppmv. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space when degassing to the control device or controlled recovery system.

2. The vapor space shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design.
3. A volume of purge gas equivalent to twice the volume of the vapor space must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of purge gas volume shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition 62.
4. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

B. The tank shall not be opened or ventilated without control, except as allowed by (1) below until one of the criteria in part C of this condition is satisfied.

1. Minimize air circulation in the tank vapor space.
   a. One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. Other manways or access points may be opened as necessary to remove or de-volatilize the remaining liquid. Wind barriers shall be installed at all open manways and access points to minimize air flow through the tank.
   b. Access points shall be closed when not in use

C. The tank may be opened without restriction and ventilated without control, after all standing liquid and/or sludge have been removed from the tank or the liquid and/or sludge remaining in the tank has a VOC partial pressure less than 0.02 psia. These criteria shall be demonstrated in any one of the following ways.

1. Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.
2. If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated:
   a. Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A Appendix 1.
   b. Take a representative sample of the liquid remaining in the tank and verify hexane soluble VOC concentration is less than 1000 ppmw using EPA method 1664 (may also use 8260B or 5030 with 8015 from SW-846).

3. Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 62.

D. Each occurrence and the associated emissions shall be recorded and the rolling 12-month emissions shall be updated on a monthly basis. These records shall include at least the following information:

1. the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

2. for the purpose of estimating emissions, the date, time, and other information specified for each of the following events:

   a. start and completion of controlled degassing, and total volumetric flow,

   b. all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,

   c. if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

3. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between events a and c with the data and methods used to determine it. The emissions associated with MSS activities shall be calculated using the methods used in the permit application.

E. Controlled emissions from fixed roof tanks T-842, T843A, T843B, and T843C shall be vented to the Main Flare (EPN PK-712).

F. The maximum combined rate of degassing or forced ventilation shall not exceed 1500 scf/min.

G. Controlled emissions from fixed roof tanks M-823-T1 shall be vented to scrubber (SM-823-T1). The maximum combined rate of degassing or forced ventilation shall not exceed 1500 scf/min.

H. Storage tanks M-871-T06, T-891A, and T891B shall comply with Special Conditions 65.B, 65.C, and 65.D.

66. The following additional limits apply to simultaneous MSS emissions from IFR tank roof landings and vessels authorized in Special Condition 61. For purposes of this condition, a high-volume vessel is defined as a vessel having a volume greater than 50 cubic feet but less than 15,000 cubic feet, a medium-volume vessel is defined as a vessel having a volume greater than 2 cubic feet but less than or equal to 50 cubic feet, and a low-volume vessel is defined has having a volume less than or equal to 2 cubic feet. Where indicated in this condition, fixed roof tanks are considered high volume vessels.

A. Where the VOC partial pressure of the liquid either previously stored or in which the vessel was in service is greater than 0.50 psi at the greater of the operating temperature or 95°F.

1. the venting of emissions to control during MSS is limited to any one of the following scenarios:

    a. Only one 250K barrel storage tank and 1 high-volume vessel; or

    b. One high-volume vessel, one medium-volume vessel, and any combination of two 150K barrel or 100K barrel IFR storage tanks; or

    c. One 250K barrel storage tank, a 150K barrel or 100K barrel storage tank, one medium-volume vessels, and three low volume vessels.

2. Uncontrolled emissions as authorized by this permit are limited to emissions from two internal floating roof storage tanks and one low-volume vessel, one medium-volume vessel, and 1 high-volume vessel occurring simultaneously. For purposes of this limit, fixed roof tanks meeting the volume criteria of paragraph A of this condition are considered large-volume vessels.

3. Tanks storing MTBE are limited to one tank with the roof floated at any one time.

B. Where the VOC partial pressure of the liquid either previously stored or in which the vessel was in service is less than 0.50 psi at the greater of the operating temperature or 95°F, simultaneous venting of emissions to the atmosphere are limited to the following:

1. One 250K barrel tank, one 150K barrel tank, and one 100K barrel tank; and either

2. One high-volume vessel and one low volume vessel; or

3. Three medium-volume vessels; or

4. One small-volume vessel

<u>Air Mover and Vacuum Truck Operations</u>

67. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Prior to initial use, identify any liquid in the truck. Record the liquid level and document the VOC partial pressure. After each liquid transfer, identify the liquid, the volume transferred, and its VOC partial pressure.

B. If vacuum pumps or blowers are operated when liquid is in or being transferred to the truck, the following requirements apply:

1. The vacuum/blower exhaust shall be routed to a carbon adsorber meeting the requirements of Special Condition 71.A.

2. Equip fill line intake with a "duckbill" or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

3. A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

   a. For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a "duckbill" or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

   b. The VOC or applicable pollutant exhaust concentration upon commencing each transfer, at the end of each transfer, and at least every hour during each transfer shall be recorded, measured using an instrument meeting the requirements of Special Condition 62.A or 62.B.

C. Record the volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12-month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Paragraphs A through D do not apply.

F. Vacuum trucks are limited to a maximum fill rate of 10,710 gallons per hour of liquids having a vapor pressure greater than or equal to 0.50 psia at 95F or liquids having a vapor pressure less than 0.50 psia.

G. Vacuum trucks are limited to loading 3 trucks with refinery lights (true vapor pressure of liquid greater than or equal to 0.50 psia) and three trucks with refinery heavies (true vapor pressure of liquid less than 0.50 psia) at any one time.

Frac or Temporary Tanks and Vessels

68. The following requirements apply to frac, or temporary, tanks and vessels used in support of MSS activities.

    A. The exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled, sampled, gauged, or when removing material.

    B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom.

    C. All emissions from frac tanks shall be vented to a carbon adsorber meeting the requirements of Special Condition 71.A.

    D. A daily record containing the information identified below is required for each frac tank in operation at the site each day

        1. The VOC exhaust concentration upon commencing each transfer, at the end of each transfer, and at least every hour during each transfer shall be recorded, measured using an instrument meeting the requirements of Special Condition 62.A or 62.B.

    E. These requirements do not apply to vessels storing less than 75 gallons of liquid that are closed such that the vessel does not vent to atmosphere except when filling, sampling, gauging, or when removing material.

    F. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12-month period. This record must be updated by the last day of the following month. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and ° of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled “Technical Guidance Package for Chemical Sources - Loading Operations” and standing emissions determined using: the TCEQ publication titled “Technical Guidance Package for Chemical Sources - Storage Tanks.”

Additional MSS Activities

69. Additional occurrences of MSS activities authorized by Special Condition 59 of this permit may be authorized under permit by rule only if conducted in compliance with this permit’s procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

70. All permanent facilities must comply with all operating requirements, limits, and representations during planned startup and shutdown unless alternate requirements and limits are identified in this permit. Alternate requirements for emissions from routine emission points are identified below.

A. Combustion units, with the exception of flares are exempt from NOx and CO operating requirements identified in special conditions of this permit during planned startup and shutdown if the following criteria are satisfied.

1. The maximum allowable emission rates in the permit authorizing the facility are not exceeded.

2. The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours.

3. Control devices are started and operating properly when venting a waste gas stream.

Control Devices

71. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. Each device used must meet all the requirements identified for that type of control device.

Controlled recovery systems identified in this permit shall be directed to an operating process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

A. Carbon Adsorption System (CAS).

1. The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

2. The CAS shall be sampled downstream of the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the pollutant.

3. The method of pollutant sampling and analysis shall be by detector meeting the requirements of Special Condition 62.A or 62.B.

4. Breakthrough is defined as the highest measured pollutant concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

5. Records of CAS monitoring shall include the following:

    a. Sample time and date.

    b. Monitoring results (ppmv).

    c. Canister replacement log.

6. Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30 percent of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

B. Vapor Combustor.

1. The vapor combustor unit (VCU) shall achieve a 99% control of the waste gas directed to it.

2. The temperature in, or immediately downstream of the combustion chamber of the vapor combustor shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the combustor.

3. The combustor exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency.

    The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

4. The vapor combustor shall be operated with no visible emissions.

72. Planned maintenance activities must be conducted in a manner consistent with good practice for minimizing emissions, including the use of air pollution control equipment, practices and processes. All reasonable and practical efforts to comply with Special Conditions 59 through 71 must be used when conducting the planned maintenance activity, until the commission determines that the efforts are unreasonable or impractical, or that the activity is an unplanned maintenance activity.

Additional Permit Requirements

73. The permit holder shall submit an application providing a complete as-built representation to the Heavy Condensate Upgrader project, PI-1 dated July 14, 2017 no later than 30 days after the start of operation.

Greenhouse Gas Requirements

74. Any calculation for carbon dioxide equivalent (CO_2e) emission rates required by this permit shall employ Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as amended on December 11, 2014 (79 FR 73779).

75. Where a methodology of 40 CFR Part 98 is referenced in this permit, such reference method shall be modified as follows:

    A. References to annual measurements shall be construed as rolling 12-month totals if the relevant parameter is measured on a monthly or more frequent basis.

    B. References to annual measurements that are not measured at a frequency greater than one month (e.g., quarterly or semiannual) shall be construed as the average of the most recent measurements based on a rolling 12-month period (e.g., average of 4 quarterly or 2 semiannual measurements).

76. Operational and Monitoring requirements for Combustion Devices

    A. Rolling 12-month CO_2e emissions shall be calculated each month using the methods provided at 40 CFR § 98.34(a)

    B. Combustion devices shall be operated with a net thermal efficiency of no less than 80 percent on a 12-month rolling average, excluding periods of maintenance, startup and shutdown. This shall be ensured by using the following good combustion practices: operating each device at an optimum air-fuel ratio, limiting the device's operating temperature to the extent practicable, and reducing heat loss through the use of insulating materials where feasible.

    C. Thermal efficiency shall be calculated and recorded at least monthly using equation G-1 from American Petroleum Institute (API) method 560 (4th ed. or later), Annex G using monitoring data collected as required under this permit and permit 80810, other quality-assured data, and engineering judgment.

    If the maximum range between twelve or more consecutive monthly efficiency calculations does not exceed 5 percentage points, and each calculation demonstrates compliance with the minimum efficiency requirements of this paragraph, the permit holder may elect to reduce the frequency of performing the calculation to quarterly (skipping up to two monthly calculations); provided, however, that:

    1. In case a quarterly efficiency calculation yields an efficiency value outside of the maximum range specified in this previous paragraph, monthly efficiency calculations shall be resumed.

    2. In case a quarterly efficiency calculation shows non-compliance with the minimum efficiency requirement of this paragraph, the permit holder shall assume that a condition of non-compliance occurred during each month of the previous quarter where a calculation was skipped.

D. The higher heating value (HHV) of the fuel shall be determined and recorded on a semiannual basis following procedures provided at 40 CFR § 98.34(a)(6).

The carbon content of the fuel shall be determined and recorded on a semiannual basis following the procedures provided at 40 CFR § 98.34(b)(3)

E. For facilities not equipped with a CEMS, the permit holder shall continuously monitor and record the exhaust temperature and the oxygen content of the flue gas for each combustion device. Monitoring devices shall reduce temperature and oxygen readings to six-minute averages or less and record readings at that frequency.

The temperature monitor shall be installed, calibrated or have a calibration check performed at least annually, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ±2 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

Oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2. A relative accuracy test audit (RATA) is required once every four quarter in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.

Quality assured (or valid) data must be generated when the combustion device is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the VCU operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

F. The permit holder shall install, calibrate, maintain, and operate a continuous fuel flow monitor and record the average hourly fuel gas consumption of each combustion device. Fuel flow meters shall be calibrated as provided for at 40 CFR § 98.34(b)(1).

77. Each flare covered by this permit shall be subject to the following requirements.

A. The flare shall be operated as specified in Special Condition 34, as applicable in order to minimize emissions of methane from the flare.

B. Emissions of GHG shall be calculated as specified in 40 CFR § 98.253(b), and rolling 12-month GHG emission totals from each flare shall be updated on a monthly basis.

78. The following requirements apply to the marine loading VCUs (EPNs VC-1 through VC-6), the Truck Loading VCU (EPN TVC-1) and temporary vapor combustor units authorized pursuant to Special Condition 71(B).

A. The minimum destruction/removal efficiency requirements of Special Conditions 33(A), 33(B) and 71(B) shall apply to emissions of methane from the control device.

B. In addition to pollutants specified in paragraph B of Special Condition 41, the permit holder shall perform stack sampling for emissions of methane from the control device in order to demonstrate compliance with paragraph A of this Special Condition. This

provision does not apply to temporary control devices used to control emissions from MSS activities per Special Condition 71.

C. Emissions of GHG shall be calculated as specified in 40 CFR §§ 98.253(j), (n), as applicable, and rolling 12-month GHG emission totals from each control device shall be updated on a monthly basis.

79. The following requirements apply to process vents covered by the permit.

A. The prohibition on non-fugitive releases of process vent emissions specified in Special Condition 2 shall apply to emissions of methane.

B. Control devices used to control process vent emissions shall comply with Special Condition 1 or 2 of this permit, as applicable.

C. Emissions of GHG from process vents shall be calculated as specified in 40 CFR §§ 98.253(i), or any other method of calculation otherwise specified in this permit, and rolling 12-month GHG emission totals from process vents shall be updated on a monthly basis.

80. Emissions from leaking piping components (EPN FUG) shall be minimized as follows.

A. The permit holder shall implement a Leak Detection and Repair Program for emissions of VOC as a surrogate for methane, as specified in Special Condition 45 of Permits 147681 and PSDTX1522**.** The permit holder shall tag all components and maintain a record of all fugitive components subject to this provision. The record shall be made available upon requests

B. Total rolling 12-month GHG emissions shall be calculated as provided for at 40 CFR § 98.253(l), except that mass emission rates shall be converted and recorded in units of short tons per year.

81. The following requirements apply to storage tanks covered by this permit.

A. Storage tanks shall be designed and operated as specified in Special Condition 7 of, except that paragraph 1 of Special Condition 7, concerning aggregate partial pressures above which additional control is required, is revised to apply to total hydrocarbons rather than to VOC.

B. Emissions of GHG from storage tanks shall be calculated as specified in 40 CFR §§ 98.253(m), or any other method of calculation otherwise specified in this permit, and rolling 12-month GHG emission totals from each storage shall be updated on a monthly basis.

82. The permit holder shall comply with all applicable control, monitoring, and recordkeeping requirements of this permit pertaining to planned MSS activities.

Emission Sources - Maximum Allowable Emission Rates

Permit Number 147681, PSDTX1522

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
TruckFug	Truck Loading Fugitives	VOC	13.22	45.14
TVC-1	Truck Loading Vapor Combustor	NOx	6.74	15.51
		CO	13.94	32.05
		VOC	8.26	19.00
		SO_2	0.03	0.02
		PM	0.34	0.79
		PM_{10}	0.34	0.79
		$PM_{2.5}$	0.34	0.79
MARINEFUG1	Marine Loading Fugitives Berth 1	VOC	43.38	--
MARINEFUG2	Marine Loading Fugitives Berth 2	VOC	43.38	--
MARINEFUG3	Marine Loading Fugitives Berth 3	VOC	43.38	--
MARINECAP	Marine Loading Fugitive Cap	VOC	--	80.83
VC-1	Marine Vapor Combustor 1	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
VC-2	Marine Vapor Combustor 2	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--
VC-3	Marine Vapor Combustor 3	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--
VC-4	Marine Vapor Combustor 4	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
VC-5	Marine Vapor Combustor 5	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--
VC-6	Marine Vapor Combustor 6	NOx	8.12	--
		CO	0.54	--
		VOC	5.42	--
		SO_2	0.08	--
		PM	1.03	--
		PM_{10}	1.03	--
		$PM_{2.5}$	1.03	--
VC-CAP	Marine Vapor Combustor Annual Emissions Cap	NOx	--	10.70
		CO	--	0.71
		VOC	--	5.61
		SO_2	--	0.04
		PM	--	1.36
		PM_{10}	--	1.36
		$PM_{2.5}$	--	1.36
T-250-1	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
T-250-2	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--
T-250-3	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--
T-250-4	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--
T-250-5	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--
T-250-6	250K BBL Tank	VOC	2.73	--
		H_2S	<0.01	--
T-150-1	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-2	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-3	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-4	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-5	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-6	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-7	150K BBL tank	VOC	2.39	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		H_2S	<0.01	--
T-150-8	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-9	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-10	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-11	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-150-12	150K BBL tank	VOC	2.39	--
		H_2S	<0.01	--
T-100-1	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-2	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-3	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-4	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-5	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-6	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
T-100-7	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-8	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
T-100-9	100K BBL Tank	VOC	2.53	--
		H_2S	<0.01	--
TKFRMCP	Emission Cap for Tank Farm	VOC	--	100.07
		H_2S	--	0.08
T-891A	Diesel Fuel Storage Tank	VOC	0.05	<0.01
T-891B	Diesel Fuel Storage Tank	VOC	0.05	<0.01
SM-823-T1	Acid Injection Tank (HCL 33%) Scrubber	HCL	0.03	<0.01
M-871-T06	Sulfuric Acid Storage Tank	H_2SO_4	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
PK-712	Main Flare	NOx	10.61	22.72
		CO	54.07	115.78
		VOC	78.26	151.42
		SO_2	4.15	15.44
		H_2S	0.04	0.16
FL-2	Butane Flare	NOx	6.93	1.39
		CO	50.05	10.01
		VOC	145.15	28.59
		SO_2	<0.01	<0.01
		H_2S	<0.01	<0.01
H-001	Feed Preheater	NOx	8.74	--
		CO	20.90	--
		VOC	3.15	--
		PM	5.21	--
		PM_{10}	5.21	--
		$PM_{2.5}$	5.21	--
		SO_2	11.49	--
		NH_3	2.54	--
H-002	Dubutanizer Reboiler	NOx	2.54	--
		CO	6.07	--
		VOC	0.91	--
		PM	1.51	--
		PM_{10}	1.51	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		$PM_{2.5}$	1.51	--
		SO_2	3.34	--
		NH_3	0.74	--
H-101	HDS Heater	NOx	4.82	--
		CO	3.53	--
		VOC	0.53	--
		PM	0.73	--
		PM_{10}	0.73	--
		$PM_{2.5}$	0.73	--
		SO_2	1.94	--
H-CCR12	CCR Preheater & First Interheater (FINS H-201 & H-202)	NOx	8.24	--
		CO	19.71	--
		VOC	2.97	--
		PM	4.91	--
		PM_{10}	4.91	--
		$PM_{2.5}$	4.91	--
		SO_2	10.84	--
		NH_3	2.40	--
H-CCR34	Second Interheater & Third Interheater (FINS H-203 & H-204)	NOx	5.17	--
		CO	12.38	--
		VOC	1.86	--
		PM	3.08	--
		PM_{10}	3.08	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		$PM_{2.5}$	3.08	--
		SO_2	6.80	--
		NH_3	1.50	--
H-CCR5	Stabilizer Reboiler	NOx	4.82	--
		CO	3.53	--
		VOC	0.53	--
		PM	0.73	--
		PM_{10}	0.73	--
		$PM_{2.5}$	0.73	--
		SO_2	1.94	--
H-401	Reactor Heater	NOx	3.98	--
		CO	2.91	--
		VOC	0.44	--
		PM	0.60	--
		PM_{10}	0.60	--
		$PM_{2.5}$	0.60	--
		SO_2	1.60	--
H-402	Stripper Reboiler	NOx	3.87	--
		CO	2.83	--
		VOC	0.43	--
		PM	0.59	--
		PM_{10}	0.59	--
		$PM_{2.5}$	0.59	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	1.56	--
M-801	Steam Boiler	NOx	4.53	--
		CO	10.84	--
		VOC	1.63	--
		PM	2.70	--
		PM_{10}	2.70	--
		$PM_{2.5}$	2.70	--
		SO_2	5.96	--
		NH_3	1.32	
HTRCAP	Heater and Boiler annual emissions CAP	NOx	--	140.04
		CO	--	362.21
		VOC	--	54.52
		PM	--	87.94
		PM_{10}	--	87.94
		$PM_{2.5}$	--	87.94
		SO_2	--	199.10
		NH_3	--	37.23
FWP-1	Fire Water Pump 1	NOx	8.42	0.22
		CO	4.60	0.12
		VOC	8.42	0.22
		PM	0.26	0.01
		PM_{10}	0.26	0.01
		$PM_{2.5}$	0.26	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	6.47	0.17
FWP-2	Fire Water Pump 2	NOx	8.42	0.22
		CO	4.60	0.12
		VOC	8.42	0.22
		PM	0.26	0.01
		PM_{10}	0.26	0.01
		$PM_{2.5}$	0.26	0.01
		SO_2	6.47	0.17
GEN-1	Emergency Generator 1	NOx	48.51	1.26
		CO	5.19	0.13
		VOC	1.45	0.04
		PM	0.34	0.01
		PM_{10}	0.34	0.01
		$PM_{2.5}$	0.34	0.01
		SO_2	31.23	0.81
GEN-2	Emergency Generator 2	NOx	48.51	1.26
		CO	5.19	0.13
		VOC	1.45	0.04
		PM	0.34	0.01
		PM_{10}	0.34	0.01
		$PM_{2.5}$	0.34	0.01
		SO_2	31.23	0.81
GEN-3	Emergency	NOx	48.51	1.26

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
	Generator 3	CO	5.19	0.13
		VOC	1.45	0.04
		PM	0.34	0.01
		PM_{10}	0.34	0.01
		$PM_{2.5}$	0.34	0.01
		SO_2	31.23	0.81
GEN-4	Emergency Generator 4	NOx	48.51	1.26
		CO	5.19	0.13
		VOC	1.45	0.04
		PM	0.34	0.01
		PM_{10}	0.34	0.01
		$PM_{2.5}$	0.34	0.01
		SO_2	31.23	0.81
CT-801	Cooling Tower	VOC	1.18	5.15
		PM	0.25	0.77
		PM_{10}	0.25	0.77
		$PM_{2.5}$	0.10	0.31
SG-FUG	Sale Gas Disconnect Fugitives	VOC	4.09	0.42
SAMP FUG	Sample Fugitives	VOC	1.68	7.34
		H_2S	<0.01	<0.01
FUG	Fugitive Emissions (5)	VOC	104.84	459.21
		H2S	0.04	0.16
		NH3	1.05	4.59

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
WWC	Waste Water Collection	VOC	5.14	22.51
CCR-V1	Regeneration Gas Loop Vent	VOC	0.14	0.61
		HCL	0.03	0.13
		Cl_2	0.01	0.05
CCR-V2	Lock Hopper Vent	PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
MSS	MSS Activities	NOx	8.92	1.35
		CO	38.10	5.49
		VOC	133.02	3.28
		PM	0.36	0.07
		PM_{10}	0.36	0.07
		$PM_{2.5}$	0.36	0.07
		SO_2	5.11	0.27
		H_2S	0.10	<0.01
		HCl	0.12	<0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) Exempt Solvent - Those carbon compounds or mixtures of carbon compounds used as solvents which have been excluded from the definition of volatile organic compound.
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter

Emission Sources - Maximum Allowable Emission Rates

CO	-	carbon monoxide
HCL	-	hydrogen chloride
H2S	-	hydrogen sulfide
H_2SO_4	-	sulfuric acid mist
NH3	-	ammonia
Cl2	-	chlorine
HAP	-	hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C

(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations

Date: **(DATE)**

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX172

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
TruckFug	Truck Loading Fugitives	CH_4	--	4.51
		CO_2e	--	112.86
TVC-1	Truck Loading Vapor Combustor	CO_2	--	15,453.40
		N_2O	--	0.14
		CH_4	--	0.68
		CO_2e	--	15,511.25
VC-CAP	Marine Vapor Combustor Annual Emissions Cap	CO_2	--	25,708.48
		N_2O	--	0.24
		CH_4	--	1.18
		CO_2e	--	25,808.26
TKFRMCP	Emission Cap for Tank Farm	CH_4	--	10.01
		CO_2e	--	250.17

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FWP-1	Fire Water Pump 1	CO_2	--	24.13
		N_2O	--	<0.01
		CH_4	--	0.02
		CO_2e	--	24.62
FWP-2	Fire Water Pump 2	CO_2	--	24.13
		N_2O	--	<0.01
		CH_4	--	0.02
		CO_2e	--	24.62
GEN-1	Emergency Generator 1	CO_2	--	116.42
		N_2O	--	<0.01
		CH_4	--	<0.01
		CO_2e	--	116.50
GEN-2	Emergency Generator 2	CO_2	--	116.42
		N_2O	--	<0.01
		CH_4	--	<0.01
		CO_2e	--	116.50
GEN-3	Emergency Generator 3	CO_2	--	116.42
		N_2O	--	<0.01
		CH_4	--	<0.01
		CO_2e	--	116.50

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
GEN-4	Emergency Generator 4	CO_2	--	116.42
		N_2O	--	<0.01
		CH_4	--	<0.01
		CO_2e	--	116.50
PK-712	Main Flare	CO_2	--	34,323.25
		N_2O	--	0.44
		CH_4	--	11.58
		CO_2e	--	34744.34
HTRCAP	Heater and Boiler annual emissions CAP	CO_2	--	1,150,876.78
		N_2O	--	13.33
		CH_4	--	66.63
		CO_2e	--	1,152,093.95
FL-2	Butane Flare	CO_2	--	5654.72
		N_2O	--	0.04
		CH_4	--	<0.01
		CO_2e	--	5666.06
SAMP FUG	Sample Fugitives	CH_4	--	<0.01
		CO_2e	--	12.00

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FUG	Fugitive Emissions (5)	CH_4	--	50.20
		CO_2e	--	1255.55
MSS	MSS Activities	CO_2	--	378.50
		N_2O	--	0.01
		CH_4	--	1.03
		CO_2e	--	386.13

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (GWP) found in Table A-1 of Subpart A 40 CFR Part 98 (78 FR 71904) for each pollutant: CO_2 (1), N_2O (298), CH_4(25)
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

Date: **(DATE)**

Preliminary Determination Summary

Jupiter Brownsville, LLC
Permit Numbers 147681, PSDTX1522, and GHGPSDTX172

I. Applicant

Jupiter Brownsville LLC
440 Louisiana St Ste 700
Houston, TX 77002-1054

II. Project Location

Centurion Brownsville
11700 RL Ostos road
Cameron County
Brownsville, Texas 78521

III. Project Description

Jupiter Brownsville LLC (Jupiter) has submitted an application to authorize a 168,000 barrel per day (bpd) heavy condensate upgrader facility at the existing site located in Cameron County Texas. The proposed condensate upgrader facility will produce approximately 85,200 bpd of ultra-low sulfur gasoline (ULSG) and 61,320 bpd of ultra-low sulfur diesel (ULSD). An additional bottoms product of approximately 12,840 will also be produced. Other petroleum gases such as propane may also be produced. The process will utilize conventional distillation technology and a number of other refinery conversion processes. Cameron County is currently designated as an attainment or unclassified area for all criteria pollutants. The facility is not currently a Title V major source but will become a major source upon construction of the project.

The following will be authorized in this permit.

1. Six 250,000 barrel Internal Floating Roof (IFR) storage tanks, twelve 150,000 barrel IFR storage tanks, and nine 100,000 barrel IFR storage tanks.
2. Ten new fixed roof storage tanks.
3. Three new marine loading berths for marine loading of ships and barges
4. Tank truck loading racks.
5. Railcar loading operations.
6. Two emergency generators and four emergency engines.
7. Eight heaters/boilers with heat input capacities greater than or equal to 100 MMBtu/hr and four heaters/boilers with maximum heat input capacities less than 100 MMBtu/hr.
8. Process fugitive components.
9. A debutanizer and crude tower overhead drums.
10. A sour water flash tank and sour water storage tank.
11. A new cooling tower.
12. Emissions from loading hose disconnects.
13. Emissions from depressurizing railcars.

14. Wastewater collection and treatment.
15. Vent emissions from the Continuous Catalytic Reformer.
16. Emissions associated with sampling of product and fuel gas.
17. Emissions associated with Maintenance, Start-up, and Shutdown (MSS) activities for the site.

IV. Emissions

Total allowable emissions of regulated pollutants for all permitted facilities are summarized below. The source is an existing minor stationary source as defined. Emissions increases that will occur at the source as a result of the project are summarized in Section V of this document, relating to Federal Applicability

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	984.32
NO_x	197.19
SO_2	218.46
CO	527.01
PM/PM_{10}	91.00
$PM_{2.5}$	90.54
H_2SO_4	0.01
H_2S	0.43
NH_3	41.82
CO2	1,232,909.07
CH4	146.59
N2O	14.20
CO2 Equivalents (CO2e)	1,236,362.15

CO2e - carbon dioxide equivalents based on global warming potentials of CH4 = 25, N2O = 298, SF6=22,800.

Predicted ground level concentrations for these pollutants identified in the table are discussed in Section VII below. The listed PM, PM10, and PM2.5 emissions include filterable and condensable particulate matter.

Emissions associated with MSS are authorized under an MSS emissions cap in a separate Emission Point Number (EPN) from the EPN authorizing normal operation

V. Federal Applicability

Cameron County is classified as attainment or unclassified for all criteria air pollutants, so Nonattainment review does not apply.

The project is located at a minor emitting facility (potential to emit in less than 100 tons per year [tpy] for a named source [Petroleum Refinery]). Per the table below, the project emissions increase for VOC (Ozone [O_3] precursor), NO_x, CO, and SO_2 exceed the major source significance levels. The emissions of PM, PM_{10}, and $PM_{2.5}$ exceed the respective significance levels as well as the net project emissions increases for all pollutants. Thus, the project is subject to PSD review for all pollutants.

The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD review.

Pollutant	Project Emissions (tpy)	Major Source Trigger (tpy)	Major Mod Trigger (tpy)	PSD Triggered Y/N
VOC	984.32	100	40 for PSD	Yes
NO_x	197.19	100	40 for PSD	Yes
SO_2	218.46	100	40	Yes
CO	527.01	100	100	Yes
PM	91.00	100	25	Yes
PM_{10}	91.00	100	15	Yes
$PM_{2.5}$	90.54	100	10	Yes
H_2SO_4	0.01	100	7	No
H_2S	0.43	100	10	No

The proposed project triggers PSD review for non-GHG NSR regulated pollutants. As shown in the table below, because the project increase is more than 75,000 tpy of CO2e, PSD review is triggered for GHG emissions.

Pollutant	Project Emissions (tpy)	Major Source or Major Mod Trigger Level (tpy)	PSD Triggered Y/N
CO2e	1,236,362.15	75,000	Yes

Since the source is an existing minor source, contemporaneous netting is not allowed. Since the project increase for the source exceeds the major source definition for at least one pollutant, all other pollutants are evaluated as if the source was an existing major source in that project increases are compared to the major modification significant emission rate to determine if major NSR applies.

VI. Control Technology Review

A. Federal BACT Review

Emission sources for the proposed project consist of vertical fixed roof (VFR) and internal floating roof (IFR) storage tanks, product loading (ships, barges, tank trucks, and railcars), emissions from loading hose disconnects, depressurizing of railcars containing butane, process heaters and boilers, emergency generators and engines, a heat exchange system (cooling tower), emissions from product sampling, wastewater collection and treatment facilities, process vents, fugitive sources, combustion control devices such as vapor combustors and flares, as well as emissions from MSS activities from all facilities being authorized.

As part of the best available control technology (BACT) review process, the Texas Commission on Environmental Quality (TCEQ) three-tier control technology review process was used to determine BACT requirements, with results supplemented by a review of relevant RACT/BACT/LAER Clearinghouse (RBLC) entries and a review of recently issued minor NSR and PSD permits for petroleum refineries in Texas and other states, and the TCEQ's continuing review of emissions control developments.

The permit requires the following controls, which satisfy PSD BACT for VOC, NOx, CO, SO2, PM, PM10, PM2.5, and GHG.

Storage Tanks
(37) new storage tanks/vessels are authorized, including (10) new VFR storage tanks and (27) new IFR storage tanks.

All IFR tanks will have a capacity of 100,000 barrels (4.2 million gallons) or more and store a variety of liquids with a true vapor pressure (TVP) less than 11.0 psia. Emissions of VOC and H2S will be minimized equipping the tanks with an internal floating roof composed of a mechanical shoe primary seal in conjunction with a rim mounted secondary seal. Tanks will be painted white, have submerged fill, and will be drain dry design. Proper fitting and seal integrity for the floating roof is ensured through visual inspections and any seal gap measurements specified in 40 CFR § 60.113b.

VFR T-842 will store chloride caustic. VFR tanks T-843A, T-843B, and T-843C will store spent sulfide caustic. All tanks will have a capacity of 24,000 gallons each. The tank will be painted white and have submerged fill pipe. VOC emissions from these tanks will be vented to the Main Flare (EPN PK-712).

VFR tanks T-891A and T-891B will store distillate fuel oil and will have a capacity of 875 gallons each. The tanks will be painted white and have a submerged fill pipe. Since the vapor pressure of the liquid stored is less than 0.50 psia and the capacity does not exceed 25,000 gallons, no addition control is required for these tanks.

VFR tank T-851 and drum D-854 will store sour water. Emissions from the units will be controlled by venting to heater H-001 during normal operation. Emissions will be vented to the Main Flare (PK-712) during periods that the heater is out of service.

Marine Loading Operations
BACT for control of VOC emissions from marine vessel loading operations is use of bottom or submerged fill for products with VOC vapor pressure of less than 0.5 psia corresponding to the maximum of either the operating temperature or 95 °F. For loading of products with VOC vapor pressure of 0.5 psia or greater corresponding to the maximum of either the operating temperature or 95 °F, BACT is loading under vacuum (non-inerted vessels), loading into MACT Y vapor-tight vessels (inerted vessels), and use of a vapor combustor with a guaranteed DRE of 99.9%. BACT for VOC emissions from hose disconnects is isolation of the line or hose; draining the line/hose either into the receiving vessel or a sump; and capping, plugging or blinding the line/hose after it has been drained.

Tank Truck and Railcar Loading Operations
Emission from loading tank trucks with liquids having a vapor pressure greater than or equal to 0.50 psia at the greater of the process temperature or 95 degrees Fahrenheit will be routed to a vapor combustor with a VOC destruction efficiency of at least 99.5%. Tank truck loading of liquids having a vapor pressure less than 0.50 at the maximum of the process temperature or 95 degrees Fahrenheit will be loaded uncontrolled. Tank trucks shall be leak tested using the methods described in Title 40 Code of Federal Regulations Part 63 (40 CFR 63), Subpart R.

The loading of propane and sour water is limited to loading trucks that are pressure rated and have been leak-checked and certified within the past 12 months in accordance with 49 CFR 180.407 Department of Transportation (DOT), for pressure tank trucks rated at 15 psig or greater so that all emissions are captured. Emissions from loading tank trucks with sour water shall be vapor balanced back to the sour water tank (Facility Identification Number, FIN T-851) such that no emissions from loading are vented to the atmosphere.

The loading of Butane to railcars is limited to the loading of railcars that are pressure rated land have been leak-checked and certified within the past 12 months in accordance with Class DOT-111AW or Class DOT-115AW testing so that all emissions are captured when loading.

LPG Truck and Railcar Loading: LPG (Propane and Butane) may be loaded into trucks and railcars certified as pressure-rated under US Department of Transportation regulations. BACT for VOC emissions from LPG pressurized truck and railcar loading is to limit the total isolated volume of connectors that may be vented during hose disconnects. Truck and railcar connectors must vent no more than 27 cubic centimeters of vapor to the atmosphere on being disconnected. The number of disconnects per year is also limited.

Railcar Depressurization
Railcars which previously held butane will be depressurized to the Butane Flare (EPN FL-2) until the internal pressure of the railcar is reduced to the flare header pressure. At that time the hatches to the railcar will be closed such that no uncontrolled emissions to the atmosphere will occur.

Emergency generators and firewater pumps
Four diesel-fired emergency generators (3860 hp capacity ea.) must meet 40 CFR Part 89 Tier 2 specifications for emissions of NO_x, hydrocarbon, CO, and particulate matter. Two emergency diesel-fired firewater pumps (800 hp capacity each) must meet 40 CFR Part 89 Tier 2 specifications for emissions of NO_x, hydrocarbon, CO, and particulate matter. Hours of non-emergency operation are limited to 52 hours per year for each generator and firewater pump. This is BACT for emergency use nonroad engines.

Process Fugitives: To minimize VOC emissions from piping component leaks, the permit requires use of the 28VHP LDAR program. This includes quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 ppmv for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak. Drains emitting VOC in excess of 500 ppmv will be tagged and replaced or repaired.

Process Furnaces and Heaters
The project will result in the construction of (12) new heaters/boilers. 8 of the new units will have maximum firing rates greater than or equal to 100 MMBtu/hr and will be equipped with Selective Catalytic Reduction (SCR) to reduce NOx emissions to 0.015 pounds of NOx per million British Thermal Units (MMBtu) heat input from fuel fired. 4 of the new units will have a maximum heat input less than 100 MMbtu/hr. NOx emissions from these units will not exceed 0.035 lb NOx per MMBtu of fuel fired.

CO emissions will not exceed an annual average of 50 parts per million by volume dry (ppmvd) corrected to 3% excess oxygen above stoichiometric requirements.

Units will fire either fuel gas, pipeline quality natural gas, or a mixture of the two. The maximum H2S content of the fuel gas is limited to not more than ppmv on a one hour rolling average basis. The maximum sulfur content of the natural gas is limited to no more than 2 grains of total sulfur per 100 dry standard cubic feet (dscf).

PM emissions from units with maximum firing rates greater than or equal to 100 MMBtu/hr will not exceed a PM emission rate of 0.00089 lb PM per MMBtu of fuel fired (also including secondary PM emissions due from condensable ammonia).

PM emissions from units with a maximum firing rate less than 100 MMBtu/hr will not exceed a PM emission rate of 0.0075 lb PM per MMBtu fuel fired.
VOC emissions will not exceed 0.0054 lb VOC per MMBtu fuel fired.

Heat Exchange Systems
The permit requires the permit holder to conduct monthly sampling following the TCEQ Sampling Procedures Manual, Appendix P, to identify leaks in the heat exchange system. Corrective action (repair of leaks in the heat exchange system) is required in case the concentration of total strippable hydrocarbons in water entering the cooling tower exceeds 0.08 ppmw methane equivalent (equivalent to 6.2 ppmw in the spent stripping air). Repairs cannot be delayed, and emissions from the cooling tower are not authorized, in case the monitored concentration exceeds 0.8 ppmw methane equivalent (equivalent to 62 ppmw in the spent stripping air). The monitoring methodology and leak definitions are consistent with the requirements of MACT CC.

Process Vents
Off-gas streams from separation units will be captured, treated to remove sulfur compounds, and used as fuel gas for the combustion units. Vents from blowdown of the debutanizer and crude tower overhead drums and from the continuous catalytic reformer are likewise directed to control. The permit forbids any uncontrolled, non-fugitive releases of VOC from process vents or pressure relief valves.

Sampling
Samples are extracted from processes and contained in sealed containers. Each sample has a volume of approximately 16 ounces. Process samples are extracted into sealed containers and are not opened except during periods that the sample is actively being evaluated.

Wastewater treatment facilities: Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered and all emissions routed to a carbon adsorption system with a maximum VOC exit concentration of 100 ppmv. Emissions from equalization and injected air floation will be vented a control device with a minimum destruction efficiency of 99%. Prior to discharge, wastewater shall be sent to an aeration basin for removal of VOCs from the wastewater.

Flares
Flares are used to control routine emissions, planned MSS, and process upsets. BACT for VOC and for products of combustion (NO_x, CO, SO2) is use of air assist or steam to prevent smoking, and compliance with 40 CFR § 63.670 specifications for minimum combustion zone net heating value, the minimum dilution parameter net heating value, and maximum tip velocity to ensure a destruction/removal efficiency (DRE) of at least 98%.

Vapor Combustors
Vapor Combustors are used to control routine loading emissions and planned MSS. BACT for VOC is a minimum DRE of 99%.

Maintenance, Startup and Shutdown Activities

The permit requires the following controls to minimize VOC emissions during planned MSS activities.

Tank Floating Roof Landings:
For floating roof storage tanks which previously stored a liquid having a vapor pressure greater than or equal to 0.50 at the greater of the process temperature or 95 °F, the vapor space under the floating roof must be routed to a control device during periods of standing idle and degassing until the vapor space VOC concentration has been verified to be 5,000 ppmv or less. The tank cannot be ventilated without control until the vapor pressure of any liquid/matierial remaining in the tank has been reduced to a vapor pressure of 0.02 psia or less. The tank roof must be landed on its lowest legs unless tank entry is planned. The tank Refilling must also be controlled if the product stored has a VOC vapor pressure of 0.50 psia or greater.

For floating roof storage tanks which previously stored a liquid having a vapor pressure less than 0.50 psia at the greater of the process temperature or 95 °F, the vapor space under the floating roof may be vented to the atmosphere uncontrolled during periods of standing idle. Emissions from degassing must be vented to control for at least four tank volumes. The tank cannot be ventilated without control until the vapor pressure of any liquid/material remaining in the tank has been reduced to a vapor pressure of 0.02 psia or less.

Fixed Roof Tanks
For fixed roof storage tanks which previously stored a liquid having a vapor pressure greater than or equal to 0.50 at the greater of the process temperature or 95 °F, the vapor space under the floating roof must be routed to a control device until the vapor space has been degassed to a verified VOC concentration of 4,000 ppmv or less. The tank cannot be ventilated without control until the vapor pressure of any liquid or material remaining in the tank has been reduced to a vapor pressure of 0.02 psia or less.

For fixed roof storage tanks which previously stored a liquid having a vapor pressure less than 0.50 at the greater of the process temperature or 95 °F, the tank cannot be ventilated without control until the vapor pressure of any

liquid or material remaining in the tank has been reduced to a vapor pressure of 0.02 psia or less

Vessels and piping components:

All vessels must be completely drained of liquid prior to opening.

If the vessel or fugitive component previously handled a material with a vapor pressure greater than 0.50 psia at the greater of the operating temperature or 95 °F, the vessel and/or component must be must be depressurized/degassed to control until the VOC concentration has been reduced to 5,000 ppmv for low and medium volume vessels and 4,000 ppmv for high volume vessels (greater than or equal to 153 cubic feet). An exemption to this requirement occurs if all the following conditions are met:

1. it is not technically practicable to depressurize or degas as applicable into the process.
2. There is not an available connection to a plant control system.
3. There is no more than 50 lb of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

If the vessel or fugitive component previously handled a material with a vapor pressure less than 0.50 psia but greater than 0.10 psia at the greater of the operating temperature or 95 °F and has a volume greater than 50 cubic feet, the vessel and/or component must be must be depressurized/degassed to control until the VOC concentration has been reduced to 750 ppmv.

For all other scenarios where the vessel or fugitive component previously handled a material with a vapor pressure less than 0.50 psia at the greater of the operating temperature or 95 °F, emissions may be vented to the atmosphere uncontrolled.

Vacuum Trucks

Emissions from loading vacuum trucks must be vented to a carbon adsorber with a maximum exit concentration of 100 ppmv.

Frac or Temporary Tanks and Vessels

Must be painted white and have a fill pipe no more than 6 inches from tank bottom. Emissions from tanks must be vented through a carbon adsorber with a maximum exit concentration not to exceed 100 ppmv. Total frac tank emissions must be calculated monthly and are subject to the permit allowable limit.

Furnace/heater startup

Units may exceed NOx and CO emission standards (lb NOx/MMBtu and ppmvd CO) authorized for normal operation during unit start-up provided the emission limits of the MAERT are not exceeded. Emission standards may be exceeded provided they occur for periods not to exceed 8 hours and the firing rate does not exceed 75% of the design firing rate.

Sources of GHG

For combustion devices subject to BACT for GHG (heaters and boilers), the permit requires a minimum net thermal efficiency of 80% on a 12-month rolling average, excluding periods of maintenance, startup and shutdown. Compliance must be demonstrated through periodic monitoring of fuel usage, fuel heat content, exhaust temperature, and exhaust oxygen content. The permit requires (at a minimum) that the applicant install an automated air-to-fuel controller in each combustion device, limit the device's operating temperature to the extent practicable, and use appropriate insulating materials to limit heat loss. The thermal efficiency must be calculated and recorded at least monthly following API method 560.

For all other sources of GHG, the permit requires that the applicant adhere to all control and work practice standards applicable to sources of VOC emissions. These include leak detection and repair programs for heat exchange systems and piping components, and a minimum destruction efficiencies from flares and vapor combustion units.

B. State Minor NSR BACT

The permit requires the following controls, which satisfy state minor NSR BACT requirements for emissions of H_2S. The TCEQ three-tier control technology review process (which includes a review of recently issued permits) was used to determine control requirements.

Storage Tanks

To minimize emissions of hydrogen sulfide (H_2S) from tanks storing crude oil, the permit limits tank service to crude oils with a liquid phase concentration of 10

parts per million by weight (ppmw) H_2S or less. H_2S concentrations are verified with annual measurements using method ASTM UOP163-10 or ASTM D7621-14. Additional test methods may be used with prior approval from the TCEQ.

VFR tank M-871-T06 will store sulfuric acid and will have a capacity of 1,480 gallons. The tank will be painted white and have a submerged fill pipe. Since the vapor pressure of the liquid stored is less than 0.50 psia and the capacity does not exceed 25,000 gallons, no addition control is required for this tank.

VFR tank M-823-T1 will store a 33% hydrochloric acid (HCL) solution and have a capacity of 925 gallons. The tank will be painted white and have a submerged fill pipe. Emissions from the tank will be vented a to a scrubber (EPN SM-823-T1) with a removal efficiency of 99% for HCL

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr, 3-hr, 24-hr, and annual SO_2, annual PM_{10}, 24-hr and annual $PM_{2.5}$ (NAAQS and Increment), and 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 24-hr PM_{10} and 1-hr and 8-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The $PM_{2.5}$ De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

a $PM_{2.5}$ NAAQS or increment based on the analyses documented in EPA guidance and policy memorandums[3].

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	20	7.8
SO_2	3-hr	427	25
SO_2	24-hr	39	5
SO_2	Annual	2	1
PM_{10}	24-hr	4.9	5
PM_{10}	Annual	1.04	1
$PM_{2.5}$ (NAAQS)	24-hr	3.4	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.9	0.2
$PM_{2.5}$ (Increment)	24-hr	4	1.2
$PM_{2.5}$ (Increment)	Annual	1	0.2
NO_2	1-hr	33	7.5
NO_2	Annual	1.9	1
CO	1-hr	187	2000
CO	8-hr	159	500

[3] www.epa.gov/nsr/significant-impact-levels-ozone-and-fine-particles

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

Intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 PSD De Minimis analyses.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.74 $\mu g/m^3$ and 0.02 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in the table above, the results are above than the De Minimis levels. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	0.58	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC).

For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. As noted above, the basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source for NO_x and the 1000 tpy Harris County source for VOC, the applicant estimated an 8-hr O_3 concentration of 0.58 part per billion (ppb). When the

estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that the 24-hr SO_2 exceeds the respective monitoring significance level and requires the gathering of ambient monitoring information.

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	39	13
PM_{10}	24-hr	4.9	10
NO_2	Annual	1.9	14
CO	8-hr	159	575

The GLCmax for all pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient SO_2 monitoring data to satisfy the requirements for the pre-application air quality analysis. Background concentrations for SO_2 were obtained from the EPA AIRS monitor 482450009 located at 1086 Vermont Ave., Beaumont, Jefferson County. The three-year average (2015-2017) of the 99th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value (33 µg/m^3). The second highest 3-hr concentration from 2017 was used for the 3-hr value (47 µg/m^3). The second highest 24-hr concentration from 2017 was used for the 24-hr value (11 µg/m^3). The annual mean concentration from 2017 was used for the annual value (1 µg/m^3). The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site. These background concentrations were also used as part of the NAAQS analysis.

The applicant evaluated ambient $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis. Background

concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 480610006 located at 344 Porter Drive, Brownsville, Cameron County. The applicant used a three-year average (2015-2017) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (25 µg/m^3). The applicant used a three-year average (2015-2017) of the annual mean concentrations for the annual value (9.5 µg/m^3). The use of this monitor is reasonable based on a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site. Additionally, this monitor is the closest $PM_{2.5}$ monitor to the project site (approximately 14.5 kilometers (km) to the southwest). These background concentrations were also used as part of the NAAQS analysis.

A background concentration for O_3 was obtained from the EPA AIRS monitor 480610006 located at 344 Porter Drive, Brownsville, Cameron County. A three-year average (2015-2017) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (57 ppb). The use of this monitor is reasonable based on a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site. Additionally, this monitor is the closest O_3 monitor to the project site (approximately 14.5 km to the southwest).

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr, 3-hr, 24-hr, and annual SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr and annual NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	31	33	64	196
SO_2	3-hr	417	47	464	1300
SO_2	24-hr	31	11	42	365
SO_2	Annual	2	1	3	80

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
$PM_{2.5}$	24-hr	3	25	28	35
$PM_{2.5}$	Annual	1	9.5	10.5	12
NO_2	1-hr	146	23	169	188
NO_2	Annual	3	4	7	100

The 1-hr SO_2 GLCmax is the highest five-year average of the 99th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the highest five-year average of the predicted annual concentrations determined for each receptor. The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual SO_2 and NO_2 GLCmax are the maximum predicted concentrations over five years of meteorological data. The GLCmax for all other pollutants and averaging times are the maximum high, second high (H2H) predicted concentrations across five years of meteorological data.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480390618 located at FM 1459 and County Road 924, Danciger, Brazoria County. The three-year average (2015-2017) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. The annual mean concentration from 2017 was used for the annual value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

The applicant performed an analysis on secondary $PM_{2.5}$ formation as part of the PSD AQA for both the NAAQS and PSD Increment analyses. The applicant evaluated project emissions of $PM_{2.5}$ precursor emissions (NO_x and SO_2). The project will result in proposed increases of NO_x and SO_2 emissions greater than 40 tons per year (tpy). The applicant also considered the NO_x and SO_2 emissions from Annova LNG Common Infrastructure LLC, Rio Grande LNG LLC, and Texas LNG Brownsville, LLC

in the secondary $PM_{2.5}$ formation analysis since these sites are currently being constructed and are not yet operating.

For the project NO_x and SO_2 emissions, as well as for Annova LNG Common Infrastructure LLC, Rio Grande LNG LLC, and Texas LNG Brownsville, LLC NO_x and SO_2 emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM) as stated above. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to MERPs. Using data associated with the 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 2.0 µg/m^3 and 0.08 µg/m^3, respectively. When these estimates are added to the total concentrations listed in Table 3 above, the results are less than the NAAQS. Though the applicant provided an analysis to support using data from the Harris County source, the applicant did not support using the 500 tpy NO_x source data for Rio Grande LNG LLC. However, using data from the 500 tpy NO_x source will not significantly affect the overall results.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 3-hr, 24-hr, and annual SO_2, annual PM_{10}, 24-hr and annual $PM_{2.5}$ (Increment), and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
SO_2	3-hr	417	512
SO_2	24-hr	31	91
SO_2	Annual	2	20
PM_{10}	Annual	4	17
$PM_{2.5}$	24-hr	7	9
$PM_{2.5}$	Annual	1	4
NO_2	Annual	3	25

The GLCmax for the 3-hr and 24-hr SO_2, and 24-hr $PM_{2.5}$ are the maximum H2H predicted concentrations across five years of meteorological data. For annual SO_2, annual PM_{10}, annual $PM_{2.5}$, and annual NO_2, the GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in Table 5 represent the total predicted concentrations associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 660 km from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.1 $\mu g/m^3$ occurred along the property line. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 52 km from the proposed sources, in the direction of the Big Bend National Park Class I area is 0.00002 $\mu g/m^3$. The Big Bend National Park Class I area is an additional 608 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 17 km from the proposed sources in the direction the Big Bend National Park Class I area. The Big Bend National Park Class I area is an additional 643 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from

the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Review

Table 6. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	420	1021
H_2SO_4	1-hr	0.7	50
H_2SO_4	24-hr	0.2	15
H_2S	1-hr	15.0	108

Table 7. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	GLCmax Location	GLCni (µg/m^3)	GLCni Location	ESL (µg/m^3)
hydgrogen chloride 7647-01-0	1-hr	23	Property Line	NA	NA	190
hydgrogen chloride 7647-01-0	Annual	< 0.01	Property Line	NA	NA	7.9
methyl tert-butyl ether 1634-04-4	1-hr	2163	Property Line	855	83m South	630
methyl tert-butyl ether 1634-04-4	Annual	8	Property Line	0.06	3.6km SW	180
ammonia 7664-41-7	1-hr	40	Property Line	NA	NA	180
refinery heavies NA	1-hr	3417	Property Line	902	98m South	1000
refinery heavies NA	Annual	110	10m South	4	91m South	100

Pollutant & CAS#	Averaging Time	GLCmax (µg/m³)	GLCmax Location	GLCni (µg/m³)	GLCni Location	ESL (µg/m³)
refinery lights NA	1-hr	8947	Property Line	3001	98m South	3500
refinery lights NA	Annual	352	Property Line	14	85m South	350

Table 8. Minor NSR Hours of Exceedance for Health Effects

Pollutant	Averagin g Time	1 X ESL GLCni	2 X ESL GLCmax
methyl tert-butyl ether	1-hr	14	15
refinery heavies	1-hr	0	37
refinery lights	1-hr	0	35

The GLCmax and the GLCni locations are listed in Table 7 above. The locations are listed by their approximate distance and direction from the property line of the project site.

The applicant did not provide the annual GLCni for methyl tert-butyl ether. The ADMT supplemented this value based on the modeling output file.

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the “Endangerment and Cause or Contribute Finding”, are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA’s PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

The applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. This permit is recommended for issuance.